Next Generation Gas Turbine Systems Study

Type of Report:	Final Report
Reporting Period Start Date:	July 17, 2000
Reporting Period End Date:	August 30, 2002
Principal Authors:	Benjamin C. Wiant Ihor S. Diakunchak Dennis A. Horazak Harry T. Morehead
Report Issue Date:	March 2003
Contract Number:	DE-AC26-00NT40851

Siemens Westinghouse Power Corporation
4400 Alafaya Trail
Orlando, Florida 32826

Disclaimer

Abstract

Under sponsorship of the U.S. Department of Energy's National Energy Technology Laboratory, Siemens Westinghouse Power Corporation has conducted a study of **Next Generation Gas Turbine Systems** that embraces the goals of the DOE's High Efficiency Engines and Turbines and Vision 21 programs**.**

The Siemens Westinghouse Next Generation Gas Turbine (NGGT) Systems program was a 24-month study looking at the feasibility of a NGGT for the emerging deregulated distributed generation market. Initial efforts focused on a modular gas turbine using an innovative blend of proven technologies from the Siemens Westinghouse W501 series of gas turbines and new enabling technologies to serve a wide variety of applications. The flexibility to serve both 50-Hz and 60-Hz applications, use a wide range of fuels and be configured for peaking, intermediate and base load duty cycles was the ultimate goal. As the study progressed the emphasis shifted from a flexible gas turbine system of a specific size to a broader gas turbine technology focus. This shift in direction allowed for greater placement of technology among both the existing fleet and new engine designs, regardless of size, and will ultimately provide for greater public benefit.

This report describes the study efforts and provides the resultant conclusions and recommendations for future technology development in collaboration with the DOE.

Table of Contents

List of Graphical Materials

List of Figures

List of Tables

1. Introduction

Siemens Westinghouse Power Corporation, under the sponsorship of the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), has completed a 24-month study evaluating the feasibility of a Next Generation Gas Turbine System. The Next Generation Gas Turbine (NGGT) Systems study was to determine the feasibility of a next generation gas turbine-based power system for the emerging distributed generation market with the goal of meeting the DOE's aggressive efficiency, emission, and cost objectives listed below.

- Improved lower heating value (LHV) net system efficiency of 15% or higher
- 50% or higher improvement in turndown ratio
- 15% or higher reduction in the cost of electricity
- Improved service life
- Reductions of emissions (carbon and oxides of nitrogen (NOx))
- 15% or higher reduction in operations, maintenance, and capital costs
- Flexibility of at least 400 starts per year, with rapid start capability
- Capability to use multiple fuels
- Improvement of reliability, availability and maintainability (RAM)

DOE's basis for determining achievement of the above goals is the comparison against 1999 state-of-the-art systems of comparable size.

The Siemens Westinghouse study initially focused on a modular gas turbine system to address the DOE NGGT system program goals and to serve a wide variety of applications. Although sound in technical approach, the concept of a single turbine system satisfying unrelated application requirements proved to be impractical from an economic standpoint. Consequently, the study shifted from developing a single turbine to developing a suite of technologies that address the DOE's performance and cost goals while accommodating the various applications and duty cycles under which gas turbine systems are expected to operate over the next twenty years.

Following an Executive Summary, this report describes the technologies that were investigated, the markets they are intended to address, benefits resulting from their implementation, and proposed development plans.

2. Executive Summary

Siemens Westinghouse's initial approach to the NGGT study was based on a modular gas turbine system that used an innovative blend of proven technologies from the Siemens Westinghouse W501 series of gas turbines and new enabling technologies to serve a wide variety of applications. The goal was to develop a modular system that would provide the flexibility to address a number of operational applications. Desired system features were: 50-Hz or 60-Hz operation, fuel flexibility, ability to serve peaking, intermediate and base load applications, and the capability of being integrated into high efficiency hybrid turbine/fuel cell systems and/or advanced central station cycles as envisioned by DOE's Vision 21 Program.

At the heart of the modular system was a high-speed, 2-shaft gas turbine configured with a power turbine that could be fitted with a blade path for either 50-Hz or 60-Hz operation. This particular configuration also provided the flexibility for being fitted with combustion burners for different fuel types, such as natural gas, oil, and syngas derived from coal, refinery residuals, biomass, and pet coke. Use of a free power turbine on it's own shaft provided ease for a reheat or fired power turbine for enhanced efficiency and power performance. Even though this nominal 130 MW gas turbine provided for many of the desired operational features and met efficiency and power performance objectives, the reality of this configuration was a more complex and costly gas turbine system.

A conventional single-shaft gas turbine of the same nominal 130 MW size was next analyzed but could still not meet the aggressive cost goals for a comparably sized gas turbine with F-class technology.

In re-evaluating the NGGT study strategy, several factors were taken into consideration before deciding on a course to pursue. These factors were: the uncertainties of future power generation markets due to the effects of deregulation in both the US and Europe, the price volatility and availability of fossil fuels, the high cost of gas turbine systems development along with the risk of designing a system size that might not be desired in the future, and the differences in near-term power generation needs of world markets. This re-evaluation led to the conclusion that investment in technological advances for gas turbine systems to achieve both performance and cost improvements would be a more prudent strategy than designing for a specific mid-sized system. This strategy was confirmed during the customer interviews held in 2002.

At this point, it was decided to look at the Siemens Westinghouse F- and G-class gas turbine frame sizes to leverage the economies of scale and determine if the use of advanced technologies could accomplish the desired design goals. One specific market driver for the US market place, the need for a very reliable large size peaking gas turbine, led to the evaluation of a large peaking engine. The large peaking engine would then serve as the "technology carrier" for the evaluation and comparison of new gas turbine technologies for meeting the DOE performance and cost improvement goals. Technology that was favorably evaluated for meeting design and financial goals could then be used in the large peaker frame or be scaled up or down for use in either existing or new gas turbine designs.

The large peaking gas turbine evaluation used the W501G as a starting platform. In order to accurately evaluate advanced technologies and concepts, a complete combined cycle model of the W501G was developed to allow concurrent evaluation of both simple and combined cycle performance. The G-class engine was chosen because it represents the latest in commercialized state-of-the-art gas turbine technologies. To provide a robust peaking engine application, capable of more than 400 starts per year, improve RAM (reliability, availability, and maintainability) and reduce the cost of electricity, the turbine inlet temperature (TIT) was reduced, the steam-cooled transitions and can-annular combustors replaced with air-cooled annular combustors, and the directionally solidified blade castings replaced with conventionally cast blades. Performance studies were then conducted by taking select technologies and inserting them into the large peaking engine, now designated W501F/G, for analysis. The results of this iterative analytical approach provided an engine with a simple-cycle efficiency exceeding the state-of-the-art by more than 12 percent, an all time high for large industrial land-based gas turbines. The combined-cycle efficiency was improved by more than 4 percent, making the engine still suitable for combined-cycle duty with a plant efficiency greater than 60.5 percent. The potential for simple cycle and combined cycle power increases were greater than 30 percent and greater than 24 percent, respectively.

From a capital cost standpoint, the W501F/G showed greater than 20% reduction as a peaking engine application when compared to the W501G applied as a peaker. The capital cost analysis also showed the potential for an additional 7-8% reduction. The best cost of electricity calculations showed a 12.7% reduction when the W501F/G was applied in a simple cycle plant using a combination of advanced materials and technologies along with optimized turbine stage pressure ratios and an advanced steam cycle.

The market analysis performed as part of the NGGT study revealed that combined cycle power plants will continue to play a significant role through the 2020 time-period for electrical capacity additions and replacements. The customer surveys conducted during the NGGT study revealed that power equipment customers are more interested in better system RAM, reduced life cycle costs, better emissions performance and more operational flexibility than continued gains in current plant efficiencies.

In summary, what this study showed was that a select combination of DOE NGGT goals could be reached for each gas turbine system. This will only be possible by the development of a range of technologies that must be combined in different ways to maximize the resulting power plant benefits for each application. This study also showed that gas turbine systems of various sizes (small, medium, and large) will continue to be a significant portion of the global power generation mix over the next twenty years with customers demanding greater equipment reliability and continued improvements in overall life cycle costs. Therefore, a recommendation for gas turbine system technology improvement, rather than a gas turbine system of a specific size, makes the most sense from a development investment standpoint.

3. System Definition

The objective of the Next Generation Gas Turbine (NGGT) Systems Program was to develop a novel concept for a greater than 30 MW system that meets a wide range of very challenging goals while servicing a broad range of applications with one cost effective base system design.

The program objectives, as specified in DOE Planned Research and Development Announcement (PRDA) were itemized in Section 1.

3.1 Technical Approach

At the start of the conceptual study, two brainstorming sessions were held with experts representing different disciplines including Engineering, Marketing, Manufacturing, Auxiliaries, Projects, Field Installation, and Service. The objective of the first session was to identify the current technologies and new technologies that should be considered for incorporation into the mid-size NGGT System to meet the Program performance, emissions, flexibility, and other goals. In total, 65 enabling technologies for potential incorporation into NGGT and 14 different systems were proposed for future evaluation. The second brainstorming session concentrated on cost reduction ideas.

The concept selected initially was a flexible, modular, two shaft design, optimized for either 50-Hz or 60-Hz operation, with the compressor and the compressor turbine on one shaft and the power turbine, which was connected to the generator, on the second shaft. The preliminary studies were carried out on a 110-MW class engine. Based on input from SWPC Marketing the engine size was increased to 130 MW at the start of the conceptual study. The two-shaft concept had significant advantages in flexibility, modularity and parts commonality between 50-Hz and 60-Hz versions, along with ease of incorporating advanced concepts such as reheat, but while initial estimates revealed that performance goals could be met, the performance and flexibility came at a large cost penalty. Because of the cost considerations, the emphasis was shifted to the single-shaft concept. As a result of additional Marketing input that higher power density would be more responsive to the market requirements, higher power single shaft versions were investigated. First the “F-Class” size was considered and finally the “G-Class” engine size was selected. The bulk of the conceptual study effort was focused on the de-rated W501G, a low cost peaker now designated as the W501F/G engine. The W501G served as a platform for evolutionary and revolutionary technology insertions, to facilitate achievement of the NGGT Program goals. Performance and cost estimates were made on the technologies that were considered for incorporation into the low cost peaker. To reduce the engine capital and operating costs many cost reduction ideas/concepts were evaluated. These technologies, ideas and concepts were then selected for incorporation on the basis of a benefit-cost analysis. The results of this conceptual study indicated that the goals of 15% improvement in simple cycle net LHV based thermal efficiency and 15% reduction in cost were achievable. In addition, if the engine were used in a combined cycle application, its net thermal efficiency would exceed 60%.

Ten different advanced technologies (Variants 1-10) were investigated as candidates for insertion into the W501G based low cost peaking engine. This report focused on simple cycle peaking operation, however the best combination of technology improvements (Variant 10) was seen to be able to achieve an efficiency of greater than 60% in combined cycle with an advanced steam cycle.

The cost model that formed the basis of the cost of each of the ten variants was based upon the W501G with a number of cost reductions and component changes and redesigns to produce the low cost peaker. The component validation costs assumed both laboratory and engine prototype testing at the factory test center for some of the variants, and testing at a customer site for others. The engineering design costs were combined with the testing and validation cost and averaged over the fleet of engines to determine the cost per engine.

By considering the cost of parts, the design and validation program costs and the simple cycle performance of the ten technology variants, the benefit-to-cost of each of the technologies could be assessed. Both the Δ NPV/Δ cost and benefit /Δ cost ratios show that technology Variant 2+3, Variant 6, and Variant 10 were significantly better than the other technologies. Based upon the cost of electricity, Variant 10 provided the lowest COE with a 12.7% reduction from the W501G. Variants 2+3, 6, and 10 provide the greatest benefit according to the benefit-cost analysis and NPV analysis.

Variant 2+3 was found by all of the analysis methods to be a promising technology. The benefit of combining technologies is also apparent in Variant 10, which combined advanced turbine materials, and technologies from Variants 1, 2+3, 5 and 6 with optimized turbine stage pressure ratios.

The results of this study showed that the W501G based low cost peaker will meet the NGGT program efficiency and cost targets, but will require a concerted effort in the development of enabling technologies.

Both performance enhancing and cost reducing technologies were reviewed and down-selected, leaving only those with high potentials for helping to meet NGGT Program goals. Some higher-risk, longer-term, promising technologies, such as *in-situ* reheat, were dropped from the evaluations in favor of other less costly technology development options.

Initially a three-phase program for the NGGT development was considered. This involved the development of three different engines over a period of 13 years. New technologies would be introduced and developed in a phased approach, culminating in the third engine, which would meet all the NGGT Program goals. Due to the change in the land based gas turbine market situation, this approach was changed to focus on one low cost peaker platform, with emphasis on enabling technologies development.

3.2 130-MW Class Two Shaft Engine

3.2.1 Engine Description

The introductory NGGT engine was to be a 130 MW Class, two shaft, low cost fuel flexible, simple cycle unit capable of delivering competitive power in the peaking through intermediate duty range (see Figure 1). The compressor was to be the scaled version of the high efficiency ATS/W501G compressor, with improved sealing, but increased tip clearances for quick start and cycling operation capabilities. The combustor technology was to be based on ultra lean premixed, catalytic design for natural gas operation and conventional diffusion flame for syngas applications. The two-stage turbine driving the compressor was to employ state-of-the-art 3D viscous aerodynamic design philosophy and advanced airfoil-cooling technology to optimize performance while using “F” technology materials to minimize costs. The two or three-stage (for 60-Hz and 50-Hz applications respectively) power turbine driving the generator was also to employ the 3D aerodynamic design and advanced cooling design for airfoils requiring cooling. Advanced sealing was to be incorporated on all rotating and stationary components as needed to improve performance. An inter-turbine duct connected the compressor turbine and the power turbine. An aerodynamically optimized side exhaust ducted the turbine exit flow into the exhaust stack. The intent of the two-shaft concept was to optimize the performance of the common “gas generator” by designing it for optimum rotational speed, and to use a different power turbine for either 50-Hz or 60-Hz applications.

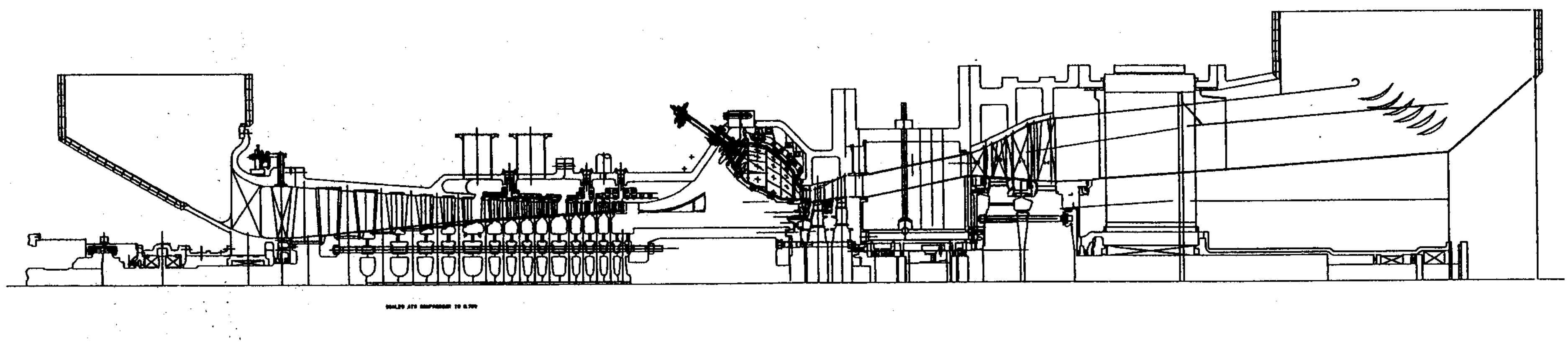


Figure 1 – 130-MW Class Two-Shaft Engine Cross Section

3.2.2 Engine Performance

Preliminary conceptual designs were carried out on the 130 MW engine components to establish approximate dimensions, number of stages, number of airfoils, cooling requirements, flow conditions in the turbine, and other design parameters, and to ensure that the conceptual study would reflect viable component designs meeting the Siemens Westinghouse design life requirement. This information was used in estimating component and engine performance. The turbine preliminary design code was run to calculate airfoil losses and stage efficiencies. Using the results of this calculation and the estimated performance of other components, such as the estimated performance of the compressor, combustor, inter-turbine duct and the exhaust duct, the Gate Cycle® code was run to estimate engine performance. All engine performance calculations were done on natural gas fuel at ISO conditions -- at sea level, 59°F ambient temperature, 60% relative humidity, and with typical inlet and exhaust losses, generator efficiency and step-up transformer losses.

The introductory (Phase 1) engine performance was estimated assuming “F” Class firing temperature. The estimated engine efficiency of this engine was close to the target value. Then new/advanced technologies were inserted and the firing temperature was increased for Phase 2 and 3 engines. The final engine version, introduced in the year 2015 time frame, would exceed the NGGT Program simple cycle efficiency goal of greater than 15% improvement. In combined cycle application, its net LHV based efficiency would be greater than 60%.

3.2.3 Engine Cost

To compare the Phase 1 engine cost a 130 MW simple cycle “Base Engine” cost model was developed. This model was based on the current Siemens Westinghouse Power Corporation (SWPC) production engine technology with the following assumptions: 130 MW size, single shaft, two bearing, axial exhaust, 14 DLN can annular combustors, same number of compressor stages and airfoils as in W501FD, similar materials as in W501FD, and similar manufacturing/assembly procedures. This estimate was based on SWPC proprietary cost models for W501D5A, W501F and W501G engines, with corrections applied for size and weight differences. Component weights for the “Base Engine” were estimated for scaling the material machining and assembly costs from the proprietary engine cost models. As a check, this cost estimate was compared to the cost of a hypothetical 130 MW engine derived from an average curve of $/kW versus MW for all heavy duty industrial/utility gas turbines in the 80 to 200 MW range published in the Gas Turbine World Handbook. The resulting “Base Engine” cost was then reduced by 15% to serve as a benchmark for achieving the NGGT Program’s 15% cost goal.

The two-shaft 130 MW engine cost was estimated as the sum of the following seven categories:

1. Compressor: inlet guide vanes, diaphragms, blades, blade rings;
2. Turbine: vane segments, blades, blade rings, isolation rings, ring segments, seal housings;
3. DLN combustion system (annular combustor);

4. Cylinders (including ducting), compressor and turbine supports;
5. Rotor assembly, blade locking hardware, miscellaneous hardware;
6. Longitudinal assembly; and
7. Freight cost for delivering hardware/components to the factory.

The resulting two-shaft engine cost was in excess of the target cost. The cost reduction ideas generated during the previously described brainstorming session were then investigated to estimate their impact on the engine cost. These ideas included: alternate compressor cylinder material and novel fabrication methods, optimized compressor stator design/fabrication, reduced number of turbine blade rings and isolation rings, simplified blade locking, and simplified turbine vane casting/insert cooling hole design. Applying the above cost reduction ideas resulted in a significant cost reduction. However, the required cost reduction target was still not achieved.

3.2.4 NGGT Engine Development Costs

To estimate what funding would be required to develop Phases 1, 2, and 3 engines, a fairly detailed costing effort was carried out. To obtain a complete and as accurate as possible cost estimate for the development costs the following costs were considered: detailed component/engine design, component performance validation (including compressor/turbine rig tests), turbine airfoil cooling design tests (both stationary and rotating, and at operating temperatures and pressures), combustion system tests (including syngas), tooling manufacturing development, prototype engine manufacturing, first article inspection, and engine field validation testing (including any required redesigns and subsequent engine re-testing). These engine development costs were combined with materials instrumentation/sensors/NDE inspection, steam turbine generator, and balance of plant development costs to produce the final program development costs. As a result of the high estimated development costs for this three-phase approach, and in the context of the current market conditions for land based gas turbines, it was decided that this approach was unrealistic. Instead, the NGGT program was redirected to enabling technology development. To evaluate benefits and costs of the identified and selected technologies, a technology “carrier platform” was to be selected and further performance and cost calculations were to be done on this platform. One of the advantages of this approach is that as the technologies are developed and validated they can be retrofitted into the current engine fleet and the benefits realized long before a full-fledged NGGT engine is developed and commercialized.

3.3 130-MW Class Single Shaft Engine

Due to the considerably higher cost and marginal performance advantage of the two-shaft engine, it was decided to investigate the single shaft 130 MW variant. This engine would reflect the current SWPC product line, but would incorporate the same features/technologies that were considered for the two-shaft version. It would employ a single shaft, two bearing, cold-end drive concept, scaled W501G compressor, annular DLN combustor, advanced 3D viscous four stage turbine design, advanced turbine airfoil cooling and advanced sealing, axial exhaust, “F” Class firing temperature and conventional materials and coatings. The estimated engine performance was only marginally lower than that of the two-shaft design.

However, the engine cost, estimated by the same procedure as described previously, was significantly lower.

The above investigation was done for a 60-Hz design. For 50-Hz application, the engine hardware would have to be scaled by 60/50 ratio (as one possibility) to accommodate the 3000-rpm rotor speed. To get around the issue of non-commonality of parts and additional tooling costs, a unique design with a gearbox for 50-Hz or 60-Hz operation was also investigated. This approach was abandoned due to high gearbox costs, gearbox losses and the fact that, at 130 MW output power, the current gearbox technology was pushed to the limit, especially if future engine upratings were to be considered.

3.4 W501F Based Low Cost Peaker

As a result of marketing input, which indicated that higher output power in the range of 180 MW would be more desirable for the low cost peaker, using the W501F frame was considered briefly. This would basically be a W501F engine with advanced technology insertions to achieve the efficiency target, and incorporating cost reduction ideas/concepts to meet the program cost target. After a brief investigation, it was decided to concentrate on the de-rated W501G as the "enabling technology carrier". Hence, the bulk of the work was done starting with the W501G and investigating what technologies and cost reduction features would have to be incorporated into it to make it a low cost peaker meeting the DOE Program goals.

3.5 W501F/G Low Cost Peaker

3.5.1 Engine Description

The W501F/G low cost peaker builds on the technological advances incorporated in the W501G engine while addressing the cost target by the use of reduced firing temperature (down to "F" level, to allow the use of conventional materials) and previously identified cost reduction ideas. The W501G is the latest and most advanced heavy frame gas turbine, with a combined cycle net efficiency of 58%. Seven W501G's are now in commercial operation, and several more will be coming on line in the near future. In total, 28 W501G's have been sold.

The low cost peaker version has reduced firing temperature and hence uses conventionally cast first and second stage turbine blades, instead of directionally solidified blades, and does not need cooling of the third stage turbine blade. It incorporates a new advanced 13-stage compressor design (compared to 16 stages in W501G) and an annular DLN combustor. This configuration eliminates transition closed loop steam cooling, hence resulting in a significant cost reduction. It uses the advanced 3D viscous aerodynamic design four-stage W501G turbine, with modifications to materials and cooling as indicated above. Figure 2 shows the engine cross-section. It was realized right from the beginning that the efficiency target could not be achieved with a de-rated version of the W501G engine without including performance-enhancing technologies. Therefore, a total of ten variants (in addition to the base W501F/G peaker) incorporating different advanced technologies resulting in improved performance, were investigated. The objective was to determine which advanced technology, or combination of technologies, would result in both the efficiency and cost targets being achieved. For each engine version, performance and cost estimates were carried out and a benefit-to-cost analysis was done.

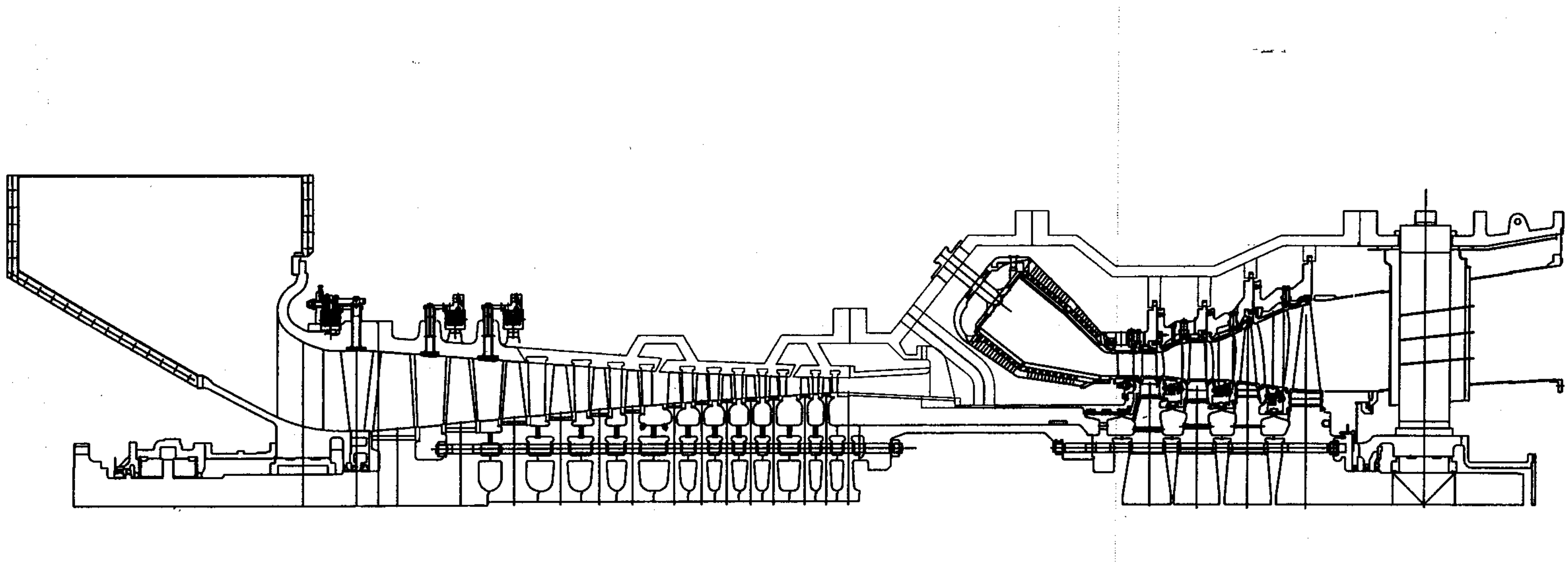


Figure 2 – W501G-Based Low-Cost Peaker Engine Cross Section

3.5.2 Engine Performance

As was done for the 130-MW engine, the Gate Cycle® program was run to estimate engine performance. For the variants incorporating new or advanced technologies, preliminary turbine designs were carried out to obtain airfoil numbers, cooling flow requirements, leakage reductions, and losses, so that accurate estimates of stage efficiencies and engine performance could be made.

Ten different technology variants were chosen for incremental integration with the W501F/G base case to arrive at various degrees of improvement in both power and efficiency. Most variants were based on other variants plus additional technology changes. (See Table 1.)

The performance estimation results are shown (in relative terms) in Table 1. Note, both simple cycle and combined cycle performance is given. The base (introductory) low cost peaker engine output power and efficiency are higher than those of the W501G engine. The significantly higher output power will make this engine attractive on a $/kW basis. However, the base case efficiency does not meet the NGGT target. The combined cycle efficiency of this variant is considerably worse than in W501G, due to its low exhaust temperature. It should be noted that some technologies such as fuel heating result in an improvement in thermal efficiency, but a reduction in output power, hence they would not be considered for incorporation in a peaker engine. The “optimized” technologies variant (Option 10 above) results in a significant increase in simple cycle output power and efficiency. The estimated simple-cycle efficiency is very close to the target value. In addition, in combined cycle application this variant will have a net efficiency greater than 60%.

Table 1
Results of Performance Estimates for the W501G-Based Low-Cost Peaker

Variant	System Description	SC Δ MW (%)	SC Δ Eta(%)	CC Δ MW (%)	CC Δ Eta(%)
Base	W501FG with New Compressor	0.0%	0.0%	0.0%	0.0%
1	Base case with aero redesign	0.6%	0.5%	0.2%	0.2%
2	Variant 3 with fuel heating and improved control rings	5.9%	3.3%	5.7%	2.1%
3	Variant 1 with leakage reduction	4.5%	1.5%	5.3%	1.5%
4	Variant 2 with higher fuel heating	5.8%	3.7%	5.7%	2.5%
5	Variant 4 with further fuel heating	5.7%	4.2%	5.5%	2.9%
6	Variant 5 with higher RIT	20.3%	3.6%	22.4%	5.5%
7	Variant 6 with fabricated blades and vanes	24.8%	3.5%	27.9%	6.0%
8	Variant 6 with improved V1, B1, B2, and B1 ring segments	22.6%	3.7%	25.1%	5.8%
9	Variant 6 with improved V1, V2, and B1 ring segments	26.1%	3.2%	29.7%	6.1%
10	Variants 6, 7, and 9 with optimized PR, and advanced steam cycle	30.2%	6.5%	31.7%	7.7%

3.6 Engine and Development Costs

The W501F/G low cost peaker was used as the technology carrier through which the DOE objectives for the NGGT would be accomplished. The W501G proprietary cost model was used as the basis for the engine cost estimation and following a similar procedure as was described for the 130 MW engine. Cost improvements were applied to the W501G to develop a low cost version, with primary focus on peaking duty. Account was taken of the fact that the redesigned compressor would have fewer stages, and hence lower cost. The cost of the compressor cylinders and rotor was scaled to reflect smaller dimensions with fewer stages. The closed-loop steam-cooled transition was eliminated and the combustion system was replaced with an annular design. As a result of reduced firing temperature, only conventionally cast airfoils were used in the turbine and no cooling was required for the third stage turbine blade. Additional potential cost savings, identified in a brainstorming session, were included to produce the engine manufactured cost.

To obtain the cost of the different engine variants, the cost increase due to the incorporation of the particular technology was estimated. For some technologies, the manufacturing costs were estimated in previous studies. For others, cost estimates had to be generated based on available information. The result was a cost estimate for each of the 10 engine variants under consideration.

The following approach was used to account for development and validation costs associated with each new technology incorporated into the NGGT engine. A heavy emphasis is placed on **validation** to ensure that risks associated with new and advanced technology introduction are minimized and RAM improved. SWPC follows a rigorous Product Development Process when introducing new technologies/products, starting with marketing requirements/specifications, through preliminary/detail design and manufacturing/testing and finally culminating in post development service follow and documentation. The individual steps impacting development costs include:

1. Component/engine preliminary and detail design (including design to cost and to 6-Sigma standards).
2. Laboratory/rig validation. For most of the technologies considered for incorporation into NGGT, a rigorous validation program will be required to minimize risks. This may include rig tests to verify component aerodynamic performance; hot and cold, stationary and rotating heat transfer tests; and materials properties verification tests.
3. Engine prototype manufacture. This includes the cost of any tooling/manufacturing process development, tooling procurement, first article inspection of all new components, and engine manufacturing costs, including higher "first of a kind" component costs for some of the components incorporating advanced technologies.
4. Engine testing (another step in risk mitigation). This includes the cost of a fully instrumented engine and extended testing at our engine test facility or at a customer site. The tests will verify performance, emissions, and mechanical integrity, and may include telemetry, optical pyrometry and thermal paints on hot end components. Initial testing may uncover technical issues that must be rectified by a redesign, if necessary, and the engine re-tested to demonstrate that the issue has been resolved.

5. Post prototype test follow and inspection. The new component or engine is monitored in the field and inspected at regular intervals to ensure that it meets the design intent/requirements.

The total costs associated with the development process described above were estimated for each of the technologies considered for introduction into the NGGT. The total technology development cost was spread over the number of engines sold with the particular technology. The assumption was made as to how many engines would be sold per year over a period of 12 years. This cost increment was then added to the previously estimated engine manufacturing cost to arrive at the total cost reflecting the added cost of new technology. Table 2 summarizes the cost estimation results in relative terms. These cost results will be used to determine which are the optimum technologies that should be considered for incorporation into the NGGT.

Table 2
Low-Cost Peaker Total Cost Summary per Engine

Variant	Δ Production Cost ($k)	Δ Cost of Technology Development ($k)	Δ Total Engine Cost ($k)
Base W501FG	-	-	-
1	-0-	275	275
2+3	338	65	403
4	200	5	205
5	400	6	406
6	350	147	497
7	1,016	144	1,160
8	778	160	938
9	429	138	567
10	1,906	266	2,172

The W501F/G engine production cost reduction exceeds the target 15% cost reduction compared to the W501G engine. On $/kW basis it betters the 15% reduction target by a wide margin compared to the W501G and the "Base Engine" cost derived from Gas Turbine World Handbook (as described in Section 3.2.3).

3.7 Benefit-to-Cost Analysis

The benefit of each of the ten technology variants was assessed using three methods. The first method determined the benefit of the technology to a customer based upon evaluation factors for power and heat rate. For each technology case, the engine was modeled to determine the power output and efficiency in simple cycle operation. Based upon the change in power and efficiency from the base evaluation case, the dollar benefit to the customer of each additional technology was assessed. The dollar benefit was then compared to the incremental cost of the engine using the advanced technology and the benefit-to-cost ratio determined. The second method of analysis calculated the net present value (NPV) of the technology based upon the customer's life-cycle costs, including power and heat rate evaluations. The change in NPV was calculated from the base case for each technology variant. The cost of electricity (COE) for each variant was used as the third comparative measure.

The base case used in this analysis is the W501G based low cost peaker, as described in Section 3.5.1. The benefit for each of the ten technology variants was assessed in terms of power and heat rate and by using an evaluation factor, which was then converted to a dollar benefit to the customer. The evaluation factors used for power and heat rate were $250/kW and $30,000 per BTU/kWh, respectively. These evaluation factors were assumed based upon a possible range of up to $600/kW and $90,000 per BTU/kWh. The benefit-to-cost ratio was the dollar benefit to the customer from increased performance compared to the increased cost of the engine with that particular technology variant. The cost for each variant is described in Section 3.6 and includes base engine cost, advanced technology components, testing and validation costs, and design and manufacturing development costs. As noted in Table 2, Variants 2 and 3 were combined for testing and validation purposes to become Variant 2+3. Hence, the engine costs used in Tables 3 and 4 below for Variants 2 and 3 do not take into account technology validation program cost.

The net present value (NPV) of an investment represents the actual value of future earnings today. NPV was used in this analysis to compare each of the technology variant's NPV, with higher NPV being better than lower NPV. A negative NPV indicates a decrease in future earnings and therefore an unfavorable investment.

The cost of electricity (COE) of each of the technology variants was also calculated using Siemens Westinghouse proprietary cost models to provide another comparative measure. The cost of electricity is used to compare equipment and represents the cost to the power plant operator to produce one kilowatt of power per hour, hence a lower COE is more favorable. The COE analysis accounts for the plant operation and maintenance costs, fuel cost and plant equipment costs along with the fuel usage. The variants that produced a large increase in power output or efficiency or both reduced the amount of fuel used, which led to a lower COE.

The results of all three analysis methods are shown in relative terms on Table 3.

Table 3
Engine Variants Ranked by Three Criteria

	Benefit/Δ Cost Ratio		Δ NPV /Δ Cost Ratio		COE Reduction (%)	
Rank	Variant	Ratio	Variant	Ratio	Variant	Δ COE
1	2+3	23.18	2+3	27.16	10	12.7%
2	10	16.20	6	22.13	2+3	6.9%
3	6	15.97	10	21.55	7	6.4%
4	1	6.24	1	6.71	8	6.3%
5	9	4.53	9	6.15	9	6.3%
6	4	4.22	4	4.40	6	6.0%
7	5	2.82	7	3.04	1	4.8%
8	7	2.26	5	2.96	5	4.7%
9	8	1.85	8	2.47	4	4.6%

Table 4
Summaries of Relative Benefit-Cost Analyses

Variant	Benefit/Δ Cost Ratio	Δ NPV /Δ Cost Ratio	COE Reduction (%)
1	6.24	6.71	4.8%
2+3	23.18	27.16	6.9%
4	4.22	4.40	4.6%
5	2.82	2.96	4.7%
6	15.97	22.13	6.0%
7	2.26	3.04	6.4%
8	1.85	2.47	6.3%
9	4.53	6.15	6.3%
10	16.20	21.55	12.7%

3.8 IGCC Plant

An investigation was carried out on the development of a syngas fuel system based on the steam-cooled W501G (ATS) engine. Initially, the syngas fuel, derived from a coal-based IGCC plant, will be burnt in a conventional gas turbine modified as required for IGCC application. The ultimate goal will be development of the required enabling technologies to achieve near zero emissions in a super efficient plant consistent with DOE's Vision 21 goals. Preliminary investigation indicated that by increasing the compressor pressure ratio to counter the increased flow through the turbine resulting from the increased flow in the IGCC application, the same turbine hardware could be used as in the gas-fired engine. Stages will need to be added to the compressor to accommodate the increased pressure ratio. Initial performance estimates indicate that 50% LHV based efficiency is achievable in this system. To achieve the 60% efficiency goal will require significant developments in new technologies.

4. Market Assessment

The potential market for NGGT systems was assessed in three steps

1. Characterize likely future power market structure and demand evolution in six key target markets,
2. Assess potential market in six key target markets, and
3. Interview key customers

The results of Steps 1 and 2 are summarized in Section 4.1 and detailed in Appendix A, and the key customer interviews are summarized in Section 4.2.

4.1 Key Target Markets Summary

In our review of the market for the next generation gas turbine systems, Siemens Westinghouse contracted PA Consulting Group to perform a market study to characterize the future power market environment over the 2007-2020 period in six key target markets (KTM). The KTMs included the United States broken down by region and five international markets: Brazil, Mexico, Germany, Italy and Spain.

Within this framework, PA Consulting was asked to complete a matrix of information based on a two-step process. Step 1 was to characterize the likely future power market structure and demand evolution in each KTM. Step two was to assess the overall market potential in each KTM which included a review of six applications comprising; pure power generation, industrial cogeneration, combined heat and power (CHP), repowering of existing sites, integrated gasification combined cycle (IGCC), and distributed generation plants larger than 30 MW.

The summary findings project a total of 304 GW to 476 GW of combined cycle (CC) and simple cycle (SC) gas turbines capacity additions in the six KTMs over the 2007-2020 period. This includes between 223 GW and 335 GW in the United States and between 81 GW and 141 GW in the five international KTMs. The estimated mix of CC/SC capacity additions would be 33% baseload, 35% intermediate, and 32% peaking. The mix is similar for both the US market and abroad but within the US regions and between countries there are differences.

In the US, the Southeast shows the highest relative baseload need and demand for potential gas turbine additions. In the international market, Mexico shows the highest relative baseload duty and need for additional capacity. Pure power generation dominates the type of applications with 64% share of all projected capacity additions in all six KTMs. This is followed by industrial cogeneration (11%), repowering (10%), decentralized generation (7%), IGCC (5%) and CHP (3%).

The various applications were assessed for likely size distribution with the average sizes as follows: 219 MW for pure power generation, 185 MW for industrial cogeneration, 91 MW for CHP, 241 MW for repowering, 267 MW for IGCC and 83 MW for distributed generation. Within the international KTMs, distributed generation additions are highest in Italy and Germany and cogeneration applications are high in both Brazil and Mexico. Across the US regions, the highest potential for repowering was projected to be in the Midwest and Northeast with the largest share of industrial cogeneration applications in the

Southeast. The configuration of gas turbines was reviewed for the merits of 2 gas turbines and one steam turbine (2x1) versus one larger gas turbine and one steam turbine (1x1) for approximately the same plant size. The conclusion was that the 2x1 configuration will tend to be used more, possibly capturing 65% of the combined cycle applications. This configuration would offer more flexibility in volatile markets and would better address load following industrial cogeneration and decentralized generation applications.

The complete market assessment titled “Market Prospects for Next Generation Turbine Systems” is included in this report as Appendix A.

4.2 Customer Surveys Summary

Between January and June 2002, Siemens Westinghouse interviewed 11 customers throughout the United States (See Figure 3) focusing on their future gas turbine R&D needs for the 2005-2020 time frame. The interviews included discussions about the current DOE goals for the High Efficiency Engine and Turbine (HEET) Program, their specific gas turbine product feature needs for the future, and their future market applications for advanced power plants. Reliability and operating flexibility were at the top of the list for almost all of the customers. While no one was willing to forecast gas prices for the long term, many of the customers included fleet wide (or portfolio wide) fuel flexibility (mostly gas and coal) near the top of their priority list.

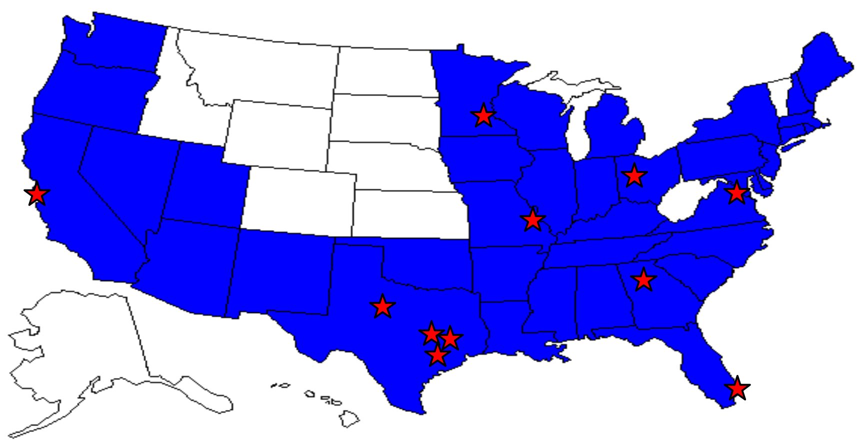


Figure 3. Location of Interviewed Customers (stars) and Their Generation Assets (blue area)

Here are the key messages from the interviewees:

Uncertainty

Many customers voiced concerns related to an uncertain future caused by regulatory uncertainty, transmission infrastructure issues, fuel price volatility, and wire charges. Their uncertainty in these areas led to uncertainty, in some cases, about the technologies they need for the future. For others, the answer was more flexible technology that can accommodate future changes.

More than one customer saw the potential for bulk power storage technologies, if implemented, to have a big impact on future markets.

Innovation and Government Support

DEREGULATION = LESS INNOVATION - Innovative technologies that cost a lot or have a large amount of risk can only be done in the rate base of a regulated utility.

Collaborative R&D with industry and DOE support needs to continue into the future since no one company can take the risk of new technologies.

The Senior Vice President of one risk-averse organization described a pioneer as “the guy with arrows in his back.” This customer is happy to be number 5 or 6. Given this perspective, risk-averse customers are supportive of the DOE’s investment in power generation, especially new materials and sensors, because they will eventually receive the benefits.

4.2.1 Demographic of Interviewees

Over the period of January to June 2002, Siemens Westinghouse met with 11 power generation customers in various parts of the country. A copy of the interview presentation is attached. Table 5 summarizes the mix of customers that were interviewed.

Table 5
Demographics of Interviewees

Customer Interviewed / # of executives interviewed	**Total Installed Capacity (GW)**	*Type*
American Electric Power / 4	42	Utility / IPP
Ameren / 2	13	Utility / IPP
Calpine / 5	14	IPP
Duke Energy NA / 3	9	IPP
Dynegy / 3	19	IPP
Florida Power and Light / 2	25	Utility / IPP
Mirant / 4	20	IPP
NRG / 2	32	IPP
PG&E National Energy Group / 2	7	IPP
Reliant / 1	18	IPP
TXU / 1	21	Utility / IPP
TOTAL	**220**	**28% of Installed US Generation Capacity**

Interviews were held with senior level managers responsible for generation, trading, and environmental issues. The interviews were scheduled for one hour each but all interviews lasted longer than an hour with a significant amount of excellent feedback provided by all of the executives. Figures 4 and 5 provide insight into the mix of companies and executives interviewed.

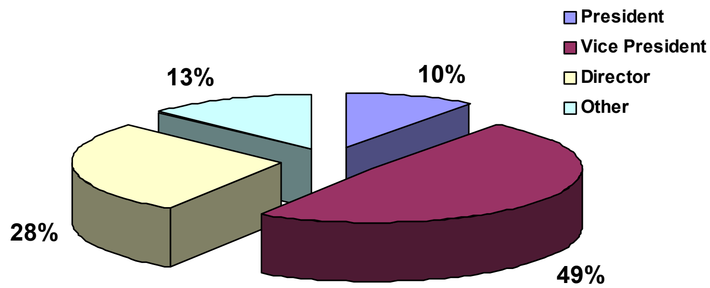


Figure 4 - Levels of Executives Interviewed

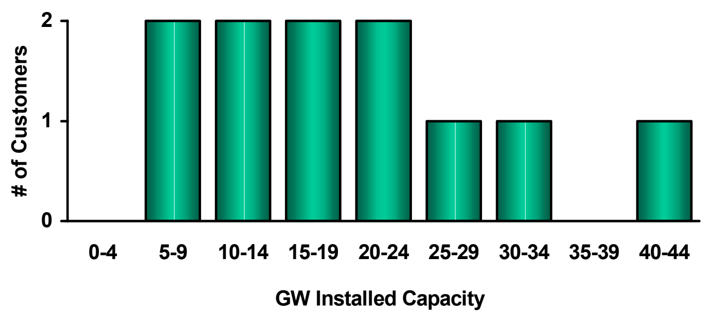


Figure 5 - Installed Capacity of Customers Interviewed

While many of the customers interviewed were utilities with defined service territories, all of the utilities interviewed had non-regulated business working as Independent Power Producers (IPPs) outside their service territory. Many of the customers also had a strong presence outside the United States.

4.2.2 Industry Feedback on DOE Goals

Reliability, operating flexibility, and reduced life cycle cost (specifically O&M costs) were the top priority goals of most customers for the 2005-2020 time frame. For some customers fuel flexibility on a fleet wide basis was also a high priority long-term goal. Environmental superiority was an important goal for many customers with some noting active technology evaluation programs in this area. While we framed the interviews to focus on the 2005-2020 time frame, our customers could not help influencing their feedback with their issues of today. Based on the customers' feedback, we have estimated their ranking of the DOE priorities. We also added the most notable new priority, "Operating Flexibility", mentioned by many of the customers. Figure 6 shows our interpretation of how the 11 customers ranked the DOE HEET Program goals based on their interview comments. Many executives had trouble ranking the goals directly, so where no direct ranking was given, rankings were based on a subjective assessment of their overall interview feedback.

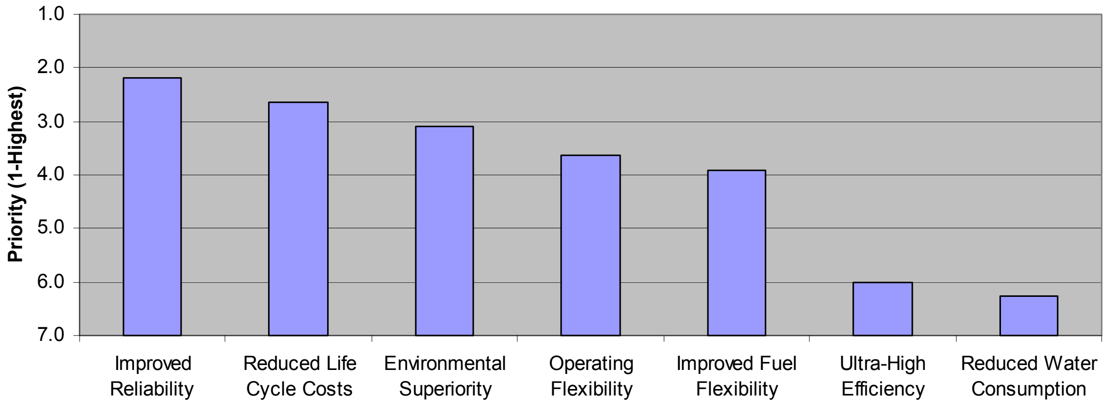


Figure 6 – Average of 11 Customers' Ranking of DOE HEET Program Goals Based on Interview Feedback

Improved Reliability

For many customers, reliability was the top priority issue. Its ranking was clearly driven by their current experience with F class gas turbines. One customer would not consider G or ATS class gas turbines anytime soon because the F class gas turbines had not proven themselves to be reliable. Customers are taking different approaches to dealing with this issue. One customer is developing in-house skills to address the issues. Another customer is focusing on standardization. One customer noted "simple is better."

Reduced Life Cycle Costs

High operation and maintenance (O&M) costs for gas turbines were by far and away the major issue raised here. Many of the customers stated that the cost of parts and long-term maintenance programs were higher than they expected. The risk associated with gas turbine parts costs have driven them to sign long term maintenance agreements with the Original Equipment Manufacturers (OEMs). One customer noted that if the F, G, and ATS class gas turbines were less risky then they would not need the long-term maintenance agreements with the OEMs. Another customer noted that these agreements are good because they make O&M costs more predictable. One executive mentioned that these agreements create a valuable expert partner in operating and maintaining their plants over the long term.

While many customers said that 15-20 year life cycle cost is important, they admitted that they still use initial cost and heat rate in their buying decisions. Some said they are working on new methods to bring long-term O&M costs into the initial buying decision. Some customers noted that once the power plant is built O&M cost is the determining factor in the plant's profitability. One company noted that for intermediate and peaking duty plants, maintenance costs dominate over reliability, fuel cost, and initial costs. Some customers suggested that more work is needed to improve parts lifing models to better account for the way units will be operated, such as including the number and frequency of starts.

High O&M costs are leading some customers to look at new technology for solutions. One customer is working with a small company to test a software based failure prediction tool (based on proximity and vibration analysis). Another customer noted that the potential for lower operating costs could overcome their resistance to using new technology. They would backstop the new technology with insurance and a good contract with the technology provider.

Environmental Superiority

All of the customers interviewed stated some level of concern about the uncertainty of future environmental regulations. One customer noted that emissions levels are being driven to zero. How they plan to deal with the uncertainty seems to vary based on their comments. Being a clean generator was a key current objective for one customer, who is actively looking at long-range emissions issues. Others want to meet the industry's current best efforts and no better at a reasonable cost. Many stated specific concerns about possible CO_2 limits, mercury control legislation, part load emissions, particulate emissions ($PM_{10}/PM_{2.5}$) limits, and noise. One customer said that SO_x and NO_x credits could reach $300-400/ton and $3,000-4,000/ton, respectively, which would add significant cost to the operation of its plants. These potential emission costs are driving this customer to look at gasification (IGCC) for future coal plants. Other customers said they would deal with the uncertainty by delaying decisions for new generation and upgrades.

Operating Flexibility

While not currently a specific goal of the HEET program, there were sufficient comments made about operating flexibility that it was added to the ranking presented above. See the specific comments under Product Feature Needs discussed below.

Improved Fuel Flexibility

Fleet wide fuel flexibility was near top priority for some customers. Many customers wanted to maintain an option for coal in the future. Some customers noted that nuclear was a good option but troubled by long development times and public perception. The two coal-based options mentioned were Integrated Gasification Combined Cycle (IGCC) and Ultra-Supercritical (USC) steam plants. Some customers are avoiding IGCC because of the historically poor reliability and high capital cost of current projects. Others saw IGCC as the only viable solution and hoped the DOE's Clean Coal Power Initiative would help accelerate the building of advanced IGCC plants by covering some of the new technology risk financially.

Ultra-High Efficiency

Ultra-high efficiency did not rank at the top of any customer's list of priorities. One customer noted that it is important for base load plants operating in a fully deregulated market. Many executives noted that their new combined cycle plants, which they purchased because of their base load performance, are in reality operating in intermediate duty (5 day/week X 16 hours/day). They did not see this situation changing in the near future. One executive noted that ultra-high efficiency units are hampered in some markets by regulated utilities being allowed to dispatch less efficient units ahead of ultra-high efficiency plants, which then operate less often.

Reduced Water Consumption

Many customers believe water use is an issue in siting new plants today and will become a more important issue in the future. Some have had to use air-cooled condensers and other technologies (such as the use of gray water) to help some of their existing plants meet permitting requirements. Based on the interview comments, the issue does seem to be more critical in some regions of the country, especially the western U.S. Some customers are looking at better heat rejection technology while others are looking at other approaches (specific technologies or cycle concepts) to address the issue.

4.2.3 Product Feature Needs

During the interviews we took the opportunity to ask each customer what specific gas turbine product feature they needed to be competitive in the 2005-2015 time frame. We have grouped the feedback into common themes in order of the total number of comments received for each theme.

Improved Reliability

One customer was willing to trade heat rate for improved reliability. For that customer, improved reliability is proving to be more important than saving fuel. Other specific comments included feedback on single shaft designs (reduces reliability and operating flexibility) and IGCC (need to be more reliable, simpler, and have better heat rates).

Operating Flexibility

Every customer requested better operating flexibility, which was one customer's "key to competitiveness." Some saw better operating flexibility as shorter startup times ("less than 10 minutes"). Some saw it in terms of plant size ("smaller is better"). Some saw it as better turndown capability ("down to 30% without higher emissions"). Others were looking at supplemental duct firing and inlet cooling to improve their operating flexibility.

Life Cycle Costs

One of the executives would like to see the industry lower the pressure ratios of future gas turbines to avoid the need for expensive natural gas booster compressor between the pipeline and the gas turbine. Another customer noted the need for new tools to maintain plant performance and the plant's availability, especially when the market needs all the power it can produce. One customer pointed out the benefits of starting a gas turbine parts life extension program to lower O&M costs based on the lessons learned in the aviation and military markets.

Low Emissions

Most of the interviewees did not have a preference on how the emissions levels were met by the OEMs as long as it was done at low cost. The rest of them had a preference for controlling the emissions with SCR technology or low emission combustors in the gas turbine. Many customers stated the need for better emissions at part load operation. One customer noted the need for low emissions technology for peaking gas turbines that operate on oil.

Controls and Sensors

Condition based or predictive diagnostics were a common request. Some see the cost of sensors as a minor cost compared to tripping a plant. One customer pointed out the benefits of wireless LAN technology as a way to reduce the cost of cable runs to the sensors. The broadest need is to have a predictive tool that helps them plan for scheduled maintenance (in both timing and scope). Beyond this basic need, some customers were looking for tools that would improve their operating flexibility by allowing more peak load operation or longer times between scheduled outages. Longer term, true remote operation (simple cycle peakers only) was mentioned where no pre- or post-operation inspections or maintenance was needed.

Some customers also cautioned us about the complexity and reliability issues related to advanced sensors, with one customer noting that complex sensors have missed important plant trip conditions. Other customers noted that the sensors need to provide information that their operators will be able to act on. They said the plant operators would bypass the sensor if they don't trust it. Again, "simple is better" was mentioned.

Plant Size

Some customers had no preference on the size of plant. A few customers thought bigger was better. Many customers thought smaller size plants (some said sized to tie into 13.8 kV distribution systems and smaller, more readily available gas lines) would be easier to site in the future. They saw this being caused by the transmission constraints and limited availability of sites near population (load) centers. "Small" ranged from under 100 MW to 300 MW. One customer was addressing this issue by designing future plants to use less space (on the order of 100 MW/acre). Many thought that to get the operating flexibility they were looking for they needed a smaller plant. Two customers noted the size of current ATS class gas turbines was too big.

Duty Cycle

One customer sees the need to design future plants for their true duty cycles. This customer would like to see plants designed primarily for a 5 day x 16 hour (~60%) duty cycle, but capable of operating as base load plants during the summer. The customer also sees benefits in designing plants as simple cycle units to shorten the time from order to operation with the capability to be easily upgraded to combined cycle operation at a later time. Many others noted the problem of operating their new base load designed plants in intermediate duty but did not offer any suggestions to improve the situation.

Faster Startup Times and More Frequent Starts

Many customers noted the value in being able to provide power to the market in less than 10 minutes. This opportunity applies to both gas and steam turbine based plants. One customer is using older coal fired plants in innovative ways to provide this capability. Another customer sees the need for gas turbines that can start twice a day year round without a significant impact on O&M costs. Another customer confirmed that some of his units are reaching 560 starts/year.

Lead Time

One customer noted that deployment was a major issue, and would like to see substantially reduced times to build and commission new plants. This customer cited the example of a modular, standardized gas turbine plant design that can "plug and play" gas turbines as needed. For example, bring the equipment on site on a couple of trailers, take off the wheels, snap the parts together, hook up the gas, and plug it in. Another customer would like to see larger plants be more like the aero-derivative based plants that can be easily moved to another site, where is takes less labor to install, and where gas turbines can be replaced in less than 3 days on site. This customer also noted that this level of flexibility was allowing the aero-based plants to beat larger plants in current evaluations.

Upgrades to Existing Fleet

Some customers expressed an interest in upgrades to their existing fleet to improve performance. Specific areas of interest include fuel flexible combustors (able to handle a wider range of gaseous fuels), increased output, better part load combustion systems, and faster start options.

4.2.4 Future Market Application Needs

We asked during the interviews what type of market applications (types of power plants) do they expect to build in the 2005-2020 time frame. We gave them the opportunity to talk about any market application, not just gas turbine based applications. Most of the feedback ended up focused on coal and gas based technologies. Many considered nuclear options troubled by public perception, long lead times, and uncertain capital costs.

IGCC

All of the customers seeking a coal based option for the future had looked at IGCC. The range of interest in IGCC went from "it's our only choice" to "it's too expensive and unreliable." Their evaluations show that gas prices need to stay above coal and petcoke by at least $ 3-4/MMBTU for a year or two for the technology to gain market share. Those that did not like the technology said the capital cost was too high (requiring a larger amount of debt) and the existing plants have not been reliable enough.

Those who liked the technology saw it as the only coal-based technology that can meet the wide range of expected emissions limits (SO_x, NO_x, Hg, CO_2 and other possible heavy metals) that might be imposed on future coal plants. One customer noted that 5 or 6 more IGCC plants need to be built before the technology is mature enough for widespread use. To deal with the risk, this customer believes that future coal-based IGCC plants will only be built in the U.S. when they can be included in the rate base of a regulated utility. Many don't see it being in widespread use until after 2010.

Asset Mix

Fleet wide fuel flexibility is an important goal for many customers. Many are considering gas, coal, and nuclear plant options. For those that are selecting gas-based plants today, they are building for the pending intermediate or peaking-duty markets. If they need base load in the future they will transition their combined cycle plant to base load operation. For those who are looking at coal based options other than IGCC, options being looked at were a 400 to 500-MW supercritical Atmospheric Circulating Fluidized Bed (ACFB) plants with back end cleanup, Pulverized Coal (PC) with supercritical steam conditions, and ultra-supercritical steam plants.

Some customers are concerned about the uncertainty of future environmental regulation. They don't believe that a PC-Steam plant, even with the best back-end cleanup technology, will be clean enough in 2020. Some are even concerned that their existing assets (coal plants) will not be re-permitted when they come up for major overhauls after 2010. This is driving some of them to focus entirely on IGCC for the future.

4.2.5 Other Important Comments

At the end of each interview we gave the interviewees the opportunity to share their final thoughts. Also during the interview the discussions would lead to a related issue not discussed above. Below are the other important comments noted during the interviews.

Some customers noted that if a disruptive technology, such as cheap and reliable bulk power storage, were introduced, many of their opinions would change. One customer, noting uncertainty in the future, is using a strategy that is best at adapting to change.

Some perceive that in the future all plants regardless of duty cycle, fuel or size will compete in a dynamic market. One customer noted this might take some time to occur since the wholesale market will be stunted until retail competition is widespread. Another customer pointed out that when full deregulation does happen, the following equation will apply:

DEREGULATION = LESS INNOVATION = NO IGCC and NO ATS CLASS OR BETTER GAS TURBINES

All but one company noted their R&D spending was down from historical levels. Many were working with EPRI using tailored collaboration to focus their R&D dollars. However, all of our customers expressed the importance of the OEMs and DOE continuing collaborative R&D into the future. Some suggested specific areas of focus such as environmental performance, reliability, and availability.

5. System Benefits

Implementation of NGGT technologies in new and retrofit applications would benefit the public and support DOE's Vision 21 Program. Section 5.1 describes the public benefits of NGGT in terms of fuel savings, emission reductions, cost savings, and job creation. Section 5.2 describes the contributions of NGGT technologies toward the realization of Vision 21.

5.1 Public Benefits

Projected US sales of new NGGT plants and retrofit-upgrades of existing plants with NGGT technology over the next 20 years, as described in this section, resulted in the following estimated public benefits.

- Figure 7 shows 447 million barrels of oil equivalent (MBOE) savings in natural gas and oil consumption, which represents 1.7% of the oil and gas projected to be used for electric power generation over the next 20 years.
  Based on values ranging from \$15 to \$25/bbl, this 20-year savings represents between \$6.7 billion and \$11.2 billion.
- Figure 8 shows 155 MBOE savings in coal consumption, which represents 0.2% of the coal projected to be used for electric power generation ("steam coal") over the next 20 years.
  Based on values ranging from \$15 to \$25/bbl, this 20-year savings represents between \$2.3 billion and \$3.9 billion.
- Figure 9 shows 0.9 million metric tons reduction in NOx emissions, which represents 1.2% of projected NOx emissions by electric power generators over the next 20 years.
  Based on values ranging from \$310 to \$1,880/ton, this 20-year savings represents between \$280 million and \$1.7 billion.
- Figure 10 shows 1.1 million metric tons reduction in SO_2 emissions, which represents 0.6% of projected SO_2 emissions by electric power generators over the next 20 years.
  Based on values ranging from \$70 to \$220/ton, this 20-year savings represents between \$78 million and \$247 million.
- Figure 11 shows 142 million metric tons reduction in CO_2 emissions, which represents 1.2% of projected CO_2 emissions by the US over the next 20 years.
  Based on values ranging from \$1.00 to \$18.60/ton, this 20-year savings represents between \$142 million and \$2.6 billion.
- Figure 12 shows \$43 billion savings in plant capital costs over the next 20 years.
- Figure 13 shows 178,000 jobs created over the next 20 years.
  Based on values ranging from \$30,600 to \$34,900/job, this 20-year benefit represents between \$5.4 billion and \$6.2 billion.

The technical approach used to estimate these public benefits is described in the pages following the figures.

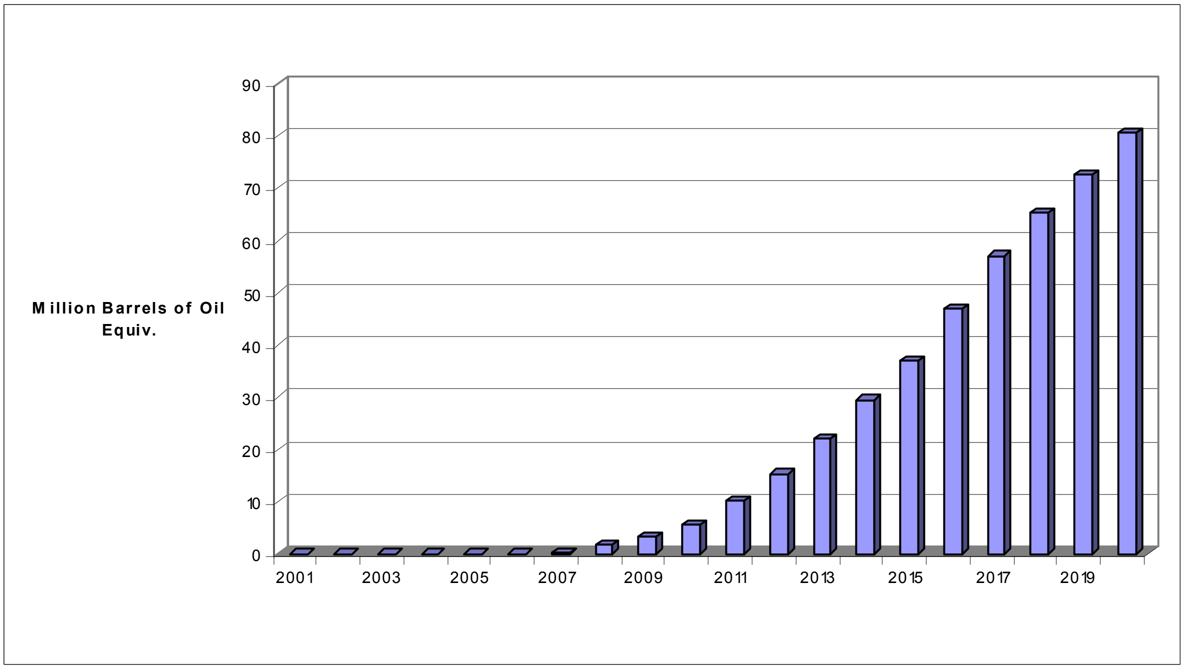


Figure 7 – Projected Gas/Oil Savings, million barrels of oil equivalent per year

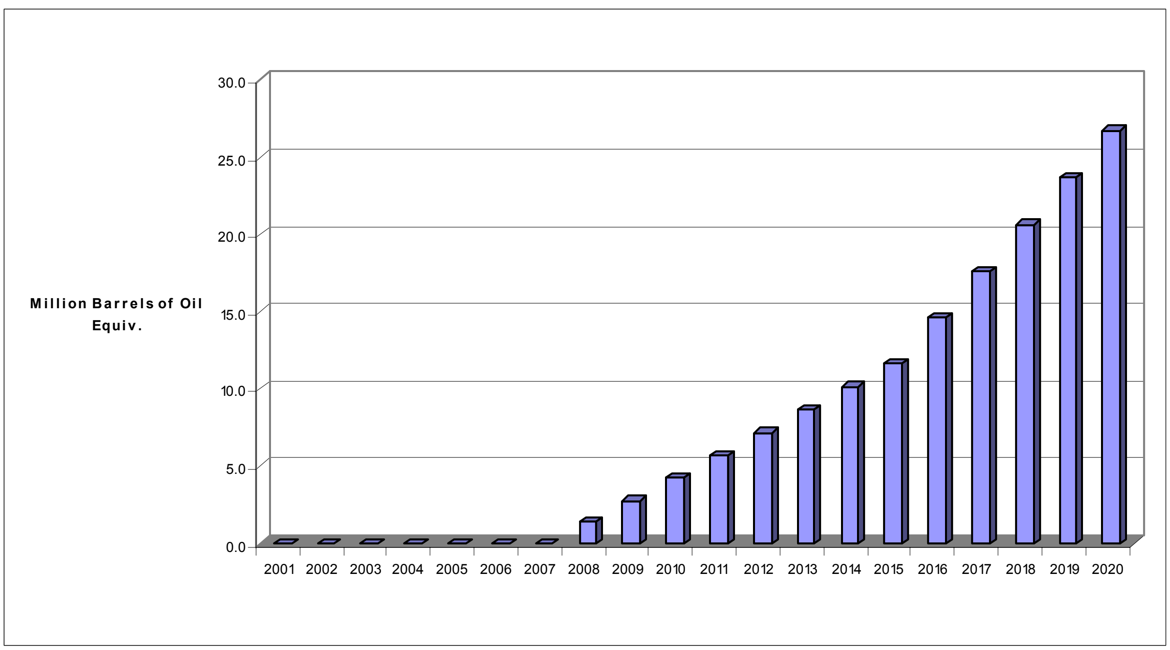


Figure 8 – Projected Coal Savings, million barrels of oil equivalent per year

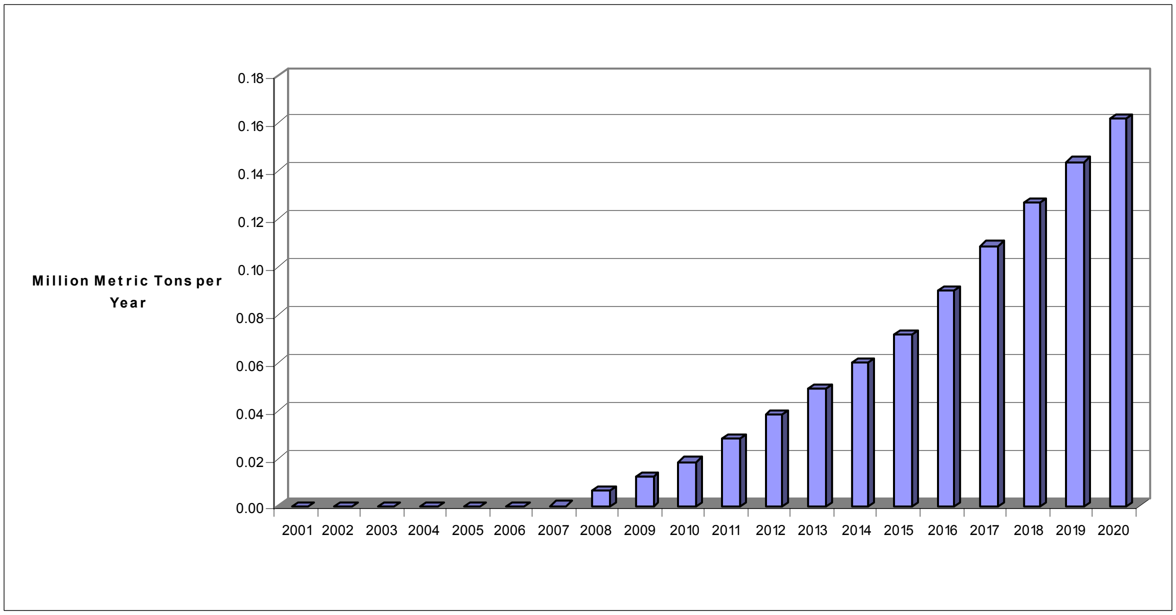


Figure 9 – Projected NOx Reduction, million metric tons per year

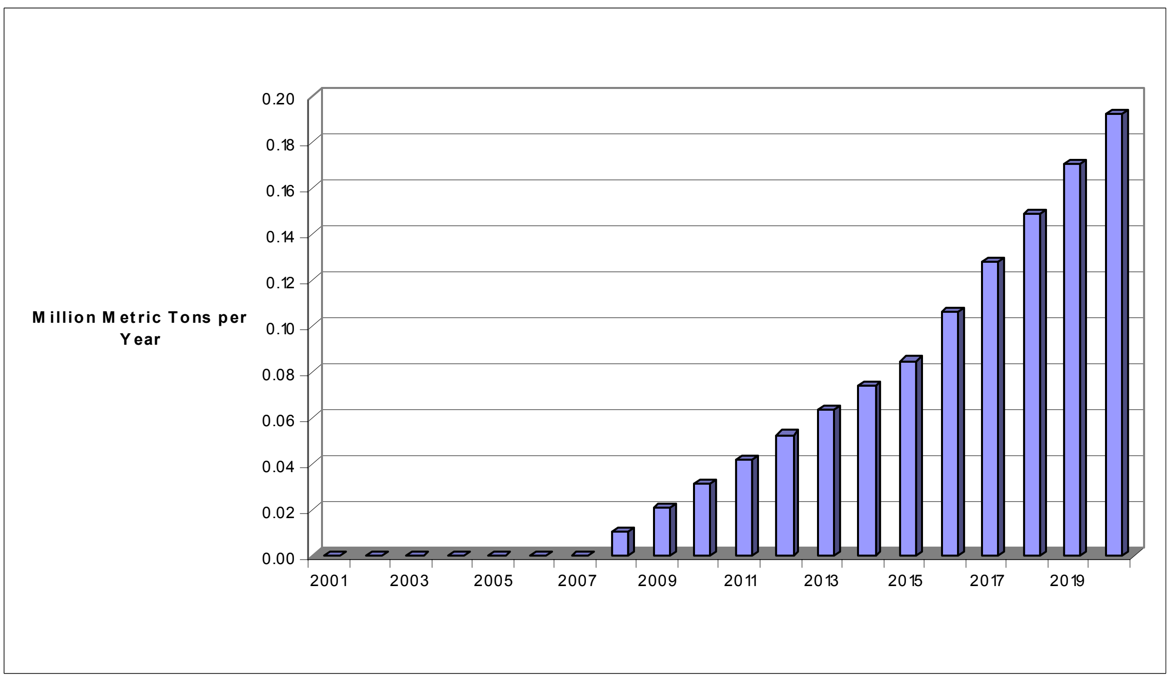


Figure 10 – Projected SO_2 Reduction, million metric tons per year

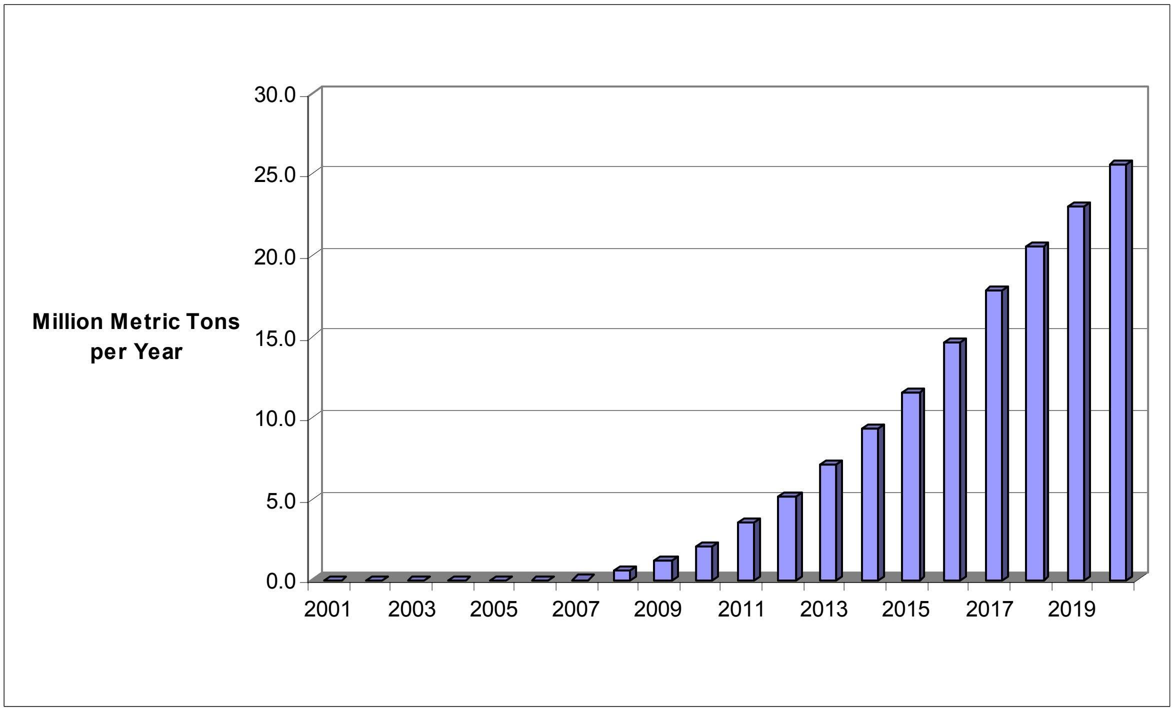


Figure 11 – Projected CO_2 Reduction, million metric tons per year

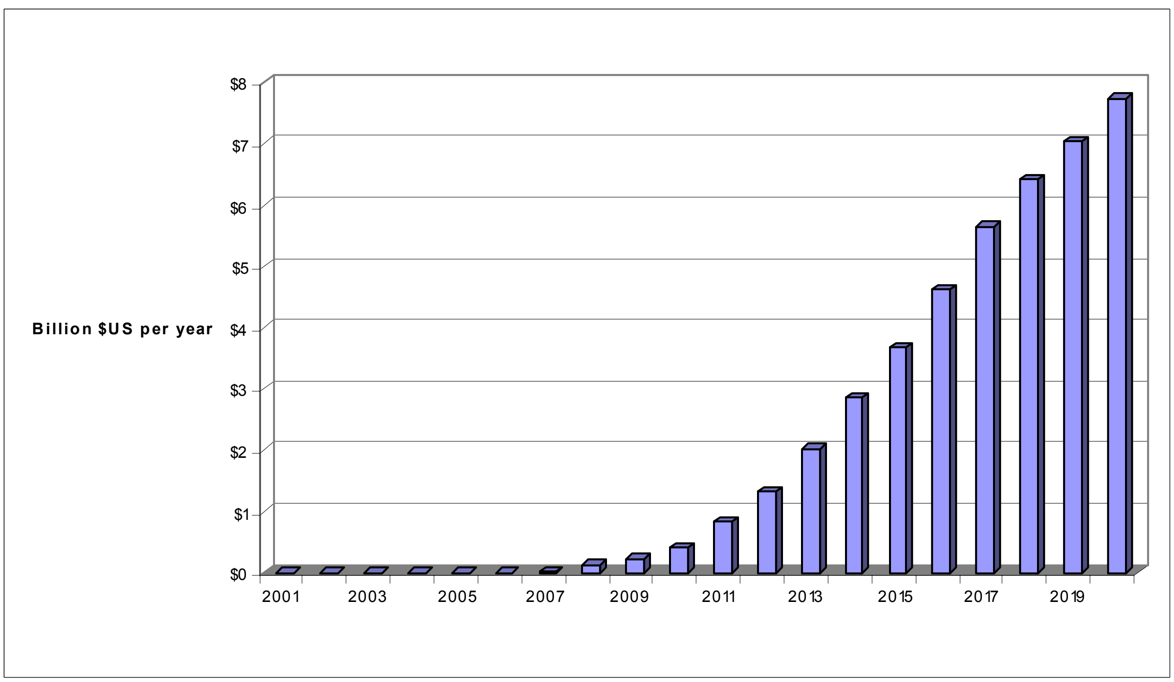


Figure 12 – Projected Capital Cost Savings, billion $US per year

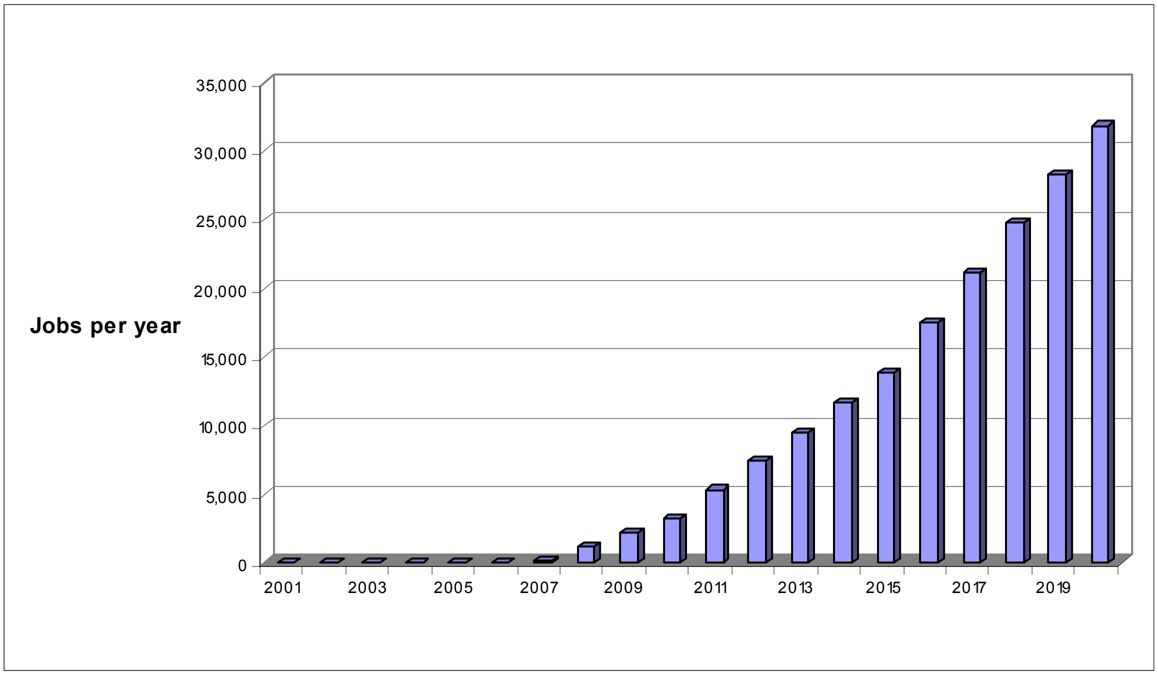


Figure 13 – Projected Job Creation, jobs per year

The overall technical approach used to estimate public benefits due to NGGT sales is broadly described in seven steps.

1. Characterize the next 20-year US electric power market based on projections by DOE/EIA in *Energy Outlook 2002 with Projections to 2020* (Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC. (www.eia.doe.gov/oiaf/aeo/assumption/tbl38.html).
2. Characterize the "status quo" gas turbines that would be installed in the US if there were no NGGT plants. Reference plant parameters (per turbine unit) include capital cost, net power output, efficiency (fuel consumption), and exhaust concentrations of NOx (ppmv, dry, 15% O_2), SO_2 (lb/MWh), and CO_2 (lb/MWh).
3. Using "status quo" turbines and the 20-year electric power market, estimate annual and 20-year total US capital cost expenditures, fuel use, NOx, SO_2, and CO_2 emissions. This is the Status Quo Scenario, without NGGT plants.
4. Characterize NGGT plants to the same level of detail as the "status quo" gas turbines.
5. Estimate the number of NGGT plants projected to be sold in each of the next 20 years. NGGT plants include various simple cycles, combined cycles, and IGCC plants that use NGGT engines.
6. Using projected NGGT sales to displace "status quo" plants, estimate annual and 20-year total US capital cost expenditures, fuel use, NOx, SO_2, and CO_2 emissions. This is the NGGT Scenario.
7. Estimate public benefits by subtracting the Status Quo Scenario from the NGGT Scenario.

Cumulative new capacity sales for the US, in gigawatts (GW) are the same EIA projections for both the "business as usual" scenario and the "with NGGT technology" scenario.

5.1.1 Estimated Plant Emissions

Emission estimates are listed in Table 6 for reference power plants, new NGGT power plants, and NGGT retrofit applications.

Table 6
Emissions Comparison

Power Plant Type	NOx, lb/MWh	SO_2, lb/MWh	CO_2, lb/MWh
Reference Power Plants			
Ref. Gas Turbine or Diesel Plants	0.933	-	1229
Ref. Combined Cycle Plants	0.616	-	812
Ref. Coal Steam Plant	3.820	9.170	1896
New NGGT Power Plants			
A1 New (2+3) Simple cycle peaker	0.165	-	1085
B2 New (10) Combined cycle plant	0.110	-	725
B6 New (10) Coal-fueled IGCC plant	0.463	0.820	1793
Retrofit NGGT Power Plants			
B4 (10) Retrofit Upgrade W501F CC (1.W501F)	0.159	-	589
B4 (10) Retrofit Upgrade W501F CC (2.W501F)	0.159	-	589
B4 (10) Retrofit Upgrade "F" Combined Cycle [1]	0.159	-	589
B5 (10) Retrofit Upgrade W501G CC (1S.W501G)	0.154	-	568
B5 (10) Retrofit Upgrade W501G CC (2S.W501G)	0.154	-	568
B5 (10) Retrofit Upgrade "G" Combined Cycle [1]	0.154	-	568

[1] Combined cycles are assumed to be a mixture of 65% 2x1 CC and 35% 1x1 CC. The resulting average net power is 1.65 times the power of a 1x1 CC.

5.1.2 NGGT Sales Projections

Unit sales projections are listed in Table 7 for new NGGT power plants and NGGT technology retrofit applications.

Table 7
NGGT New and Retrofit Unit Sales Projections

Net Power Designation	New Peaker 270 MW A1	New Comb.Cyc 791 MW B2	Retrofit W501F CC 541 MW[1] B4	Retrofit W501G CC 698 MW[1] B5	New IGCC 420 MW B6
2007	2	-	-	-	-
2008	2	1	2	1	1
2009	2	1	2	1	1
2010	2	1	5	1	1
2011	7	3	6	2	1
2012	7	3	8	3	1
2013	7	3	15	3	1
2014	7	3	20	3	1
2015	7	3	20	3	1
2016	11	5	20	4	2
2017	11	5	20	6	2
2018	11	5	10	6	2
2019	11	5	5	6	2
2020	11	5	5	8	2

[1] Combined cycles are assumed to be a mixture of 65% 2x1 CC and 35% 1x1 CC. The resulting average net power is 1.65 times the power of a 1x1 CC.

5.2 Vision 21 Support

The DOE's Vision 21 Program's primary objective is to effectively remove all environmental concerns associated with the use of fossil fuels for producing electricity, liquid transportation fuels, and high-value chemicals. Vision 21, as envisioned by DOE and supported by SWPC, brings all of the needed technologies together to allow energy production plants to perform a variety of functions in a highly efficient and environmentally friendly way. The advanced technologies being developed today for Integrated Gasification Combined Cycle (IGCC), Advanced Pressurized Fluidized Bed Combustion (APFBC), Advanced Turbine Systems (ATS), High Performance Power Systems (HIPPS), Solid Oxide Fuel Cells (SOFC), and Next Generation Gas Turbine Systems will become building blocks for future plants that can produce a variety of products from fossil fuels, including electricity and chemical feedstocks.

At the heart of the Vision 21 "Energy-plex" is gas turbine technology. The gas turbine converts the fossil fuel processed by gasification or other means into mechanical and thermal energy to eventually produce electricity and co-generation heat. We expect gas turbines of various sizes to be incorporated into Vision 21 plants. The technologies identified in this study will be developed and applied to gas turbines of various sizes and in various combinations to produce flexible and efficient power plants. The emissions and efficiency benefits inherent in these next generation technologies will readily carry over into the Vision 21 systems. The timing for the development of these next generation technologies and the Vision 21 Program are very complementary. Given the current plan, the next generation gas turbine technologies will focus on lower emissions and higher efficiency with natural gas and syngas, and will be well proven in the marketplace prior to the introduction of the first Vision 21 plants in the 2015 timeframe.

6. Technology Roadmap

Siemens Westinghouse maintains proprietary roadmaps for all major areas of technology focus, across all product lines. The roadmaps are based on various inputs including, but not limited to: customer requirements, time to develop, cost of development, current and forecasted global electricity market conditions, industry competitors, and regulatory influences both real and envisioned.

The combinations of NGGT technologies evaluated as part of the 10 variants in this study have been assessed for their potential in adding value to the Siemens Westinghouse power equipment product line and to achieving the DOE program goals. The technologies deemed evolutionary have been prioritized and integrated into the various existing technology roadmaps as technology needed to meet near term market demands. Those technologies identified as revolutionary, rather than evolutionary, have been placed on an NGGT Enabling Technologies Roadmap as candidates for collaborative development. These revolutionary or longer-term technologies are in most cases risky, will take longer to develop, have the potential to provide a greater public benefit, and probably wouldn't get developed unless done in collaboration with DOE.

Since the technologies for potential development are strategic to Siemens Westinghouse, they have been classified as proprietary and therefore are not shown in this report.

7. Development Plan

Siemens Westinghouse has identified certain NGGT system technologies for collaborative development with the DOE and identified them in a proprietary NGGT Enabling Technologies Roadmap. The NGGT Enabling Technologies Roadmap schedule was developed in conjunction with overall Siemens Westinghouse technology development plans to provide an orderly sequence of NGGT technology introduction for commercialization. Validation will be accomplished in both stand-alone test facilities and in customer operating plants.

The development schedule included consideration for introducing technology at the earliest opportunity in order to optimize return on investment and achieve the greatest public benefit in the 2005-2020 timeframe. The schedule also provides the technologies necessary to achieve DOE program goals and integration into Vision 21 "Energy-plexes" by 2015.

Figure 14 shows annual and cumulative spending for the NGGT technologies potentially developed in collaboration with DOE.

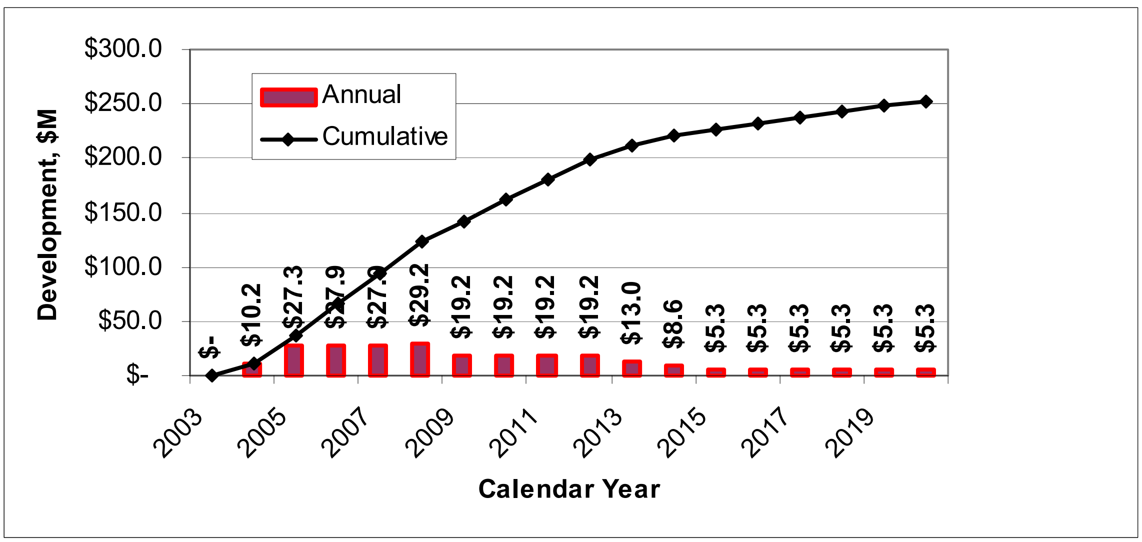


Figure 14 - NGGT Technology Development Spending Plan 2004-2020

For each of the technology options considered, validation of the advanced technology for that option was investigated. Two types of testing were required, namely laboratory validation testing and engine testing.

Laboratory validation consists of a model turbine test, which would verify turbine aerodynamic performance and outside heat transfer coefficients, heat transfer testing, and materials testing. The heat transfer testing consists of an internal cooling test for air-cooled components using plastic models, cascade testing, and a rotating rig test.

Eleven different cost elements were used to estimate the cost of development, validation, and testing. These elements were varied to produce the three engine testing scenarios.

The biggest contributor to the engine testing programs for all three scenarios was the cost of parts, which included the advanced technology components being validated and any modifications required to accommodate instrumentation installation. The cost of the parts required for testing was included as the first prototype cost, and will be significantly reduced when parts go into full-scale production.

8. Conclusions

The main conclusion derived from the NGGT System Study was that the public would be better served by developing advanced enabling technologies rather than developing a specifically sized NGGT system. Developing a range of technologies that address DOE NGGT program goals and that can be scaled up or down for use with all sizes of new gas turbine systems will provide greater public benefit. Also, as technologies are developed and validated, they can be retrofitted into the existing fleet of gas turbine systems so benefits can be realized long before a full-fledged NGGT system could be developed and commercialized, as has been done with selected ATS technologies.

Market analyses revealed that gas turbine power plants of varying sizes will continue to provide a significant portion of the global power generation mix through the 2020 time-period for electrical capacity additions and replacements. Feedback from face-to-face customer surveys revealed that power equipment customers are more interested in better system RAM, reduced life cycle costs, better emissions performance and more operational flexibility than they are in continued gains in plant efficiencies.

In summary, this study showed that select combinations of DOE NGGT goals could be reached for each gas turbine system. This will only be possible by the development of a range of technologies that must be combined in different ways to maximize the resulting power plant benefits for each application. This study also showed that gas turbine systems of various sizes (small, medium, and large) will continue to be a significant portion of the global power generation mix over the next 20 years, with customers demanding greater equipment reliability and continued improvements in overall life cycle costs. Therefore, a recommendation for gas turbine system technology improvement, rather than a gas turbine system of a specific size, makes the most sense from a development investment standpoint.

9. List of Acronyms and Abbreviations

ACFB	Atmospheric Circulating Fluidized Bed
ATS	Advanced Turbine Systems
B1, 2, …	Rotating Blade row 1, 2, …
BTU	British Thermal Unit
CC	combined cycle
CHP	Combined Heat and Power
COE	Cost of Electricity
DLN	Dry Low-NOx
DOE	U.S. Department of Energy
Eta	Thermal efficiency
GW	Gigawatt (1,000 megawatts)
HEET	High Efficiency Engines and Turbines
HHV	Higher Heating Value
HIPPS	High Performance Power System
HRSG	Heat Recovery Steam Generator
Hz	Hertz (cycles per second)
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
KTM	Key Target Markets
kWh	Kilowatt-hour
LAN	Local Area Network
LHV	Lower heating Value
MBOE	Million Barrels of Oil Equivalent (approximately 5.8 x 10^{12} BTU)
MW	Megawatts
NDE	Non-Destructive Examination
NGGT	Next Generation Gas Turbine
NPV	Net Present value
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PC	Pulverized Coal
PR	Pressure ratio
PRDA	Planned Research and Development Announcement
RAC	Rotor Air Cooling
RAM	Reliability, Availability, and Maintainability
RIT	Rotor Inlet Temperature
SC	Simple Cycle
SOFC	Solid Oxide Fuel Cells
SWPC	Siemens Westinghouse Power Corporation
TCLA	Total Cooling and Leakage Air
TIT	Turbine Inlet Temperature
USC	Ultra-SuperCritical (steam power cycle or plant)
V1, 2, …	Stationary Vane row 1, 2, …

Appendix - Market Prospects for Next Generation Turbine Systems, March 12, 2002, PA Consulting Group

PA Consulting Group

Market Prospects for Next Generation Turbine Systems

March 12, 2002

PA Consulting Group is a leading management, systems and technology consulting firm, with a unique combination of these capabilities. Established almost 60 years ago, and operating worldwide from over 40 offices in more than 20 countries, PA draws on the knowledge and experience of some 3,400 people, whose skills span the initial generation of ideas and insights all the way through to detailed implementation.

PA builds strategies for the creation and capture of shareholder and customer value, and helps clients accelerate business growth through innovation and the application of technology. PA works with clients to improve performance, mobilize human resources and deliver change effectively, including managing major projects, and designing and implementing enterprise-wide systems and full e-business solutions.

PA focuses on *creating* benefits for clients rather than merely proposing them, and this focus is supported by an outstanding implementation track record in every major industry and for governments around the world. PA also develops leading-edge technology both for its clients and within its own portfolio of venture companies in areas ranging from software to wireless technology to life sciences.

PA distinguishes itself from its competitors through the range and quality of its people, the depth of its industry insight, its development and use of technology, and also its independence and culture of respect, collaboration and flexibility in working with clients.

We are proud that our clients say ***"PA makes it happen".***

Market Prospects for Next Generation Turbine Systems

March 12, 2002

Prepared by: Jean-Louis Poirier
Gerald Schwinn
Holt Bradshaw

PA Consulting Group
1750 Pennsylvania Avenue
NW Washington
DC 20006
Tel: +1 202 442 2000
Fax: +1 202 442 2001
www.paconsulting.com

Version: 2.0

TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY FINDINGS

The U.S. Department of Energy issued in December 1999 a Program Research and Development Announcement (PRDA) which solicited offers to complete studies to determine the feasibility of developing flexible next generation turbine (NGT) systems with a greater than 30 MW power rating.

Siemens Westinghouse Power Corporation (SWPC) was awarded a contract in response to that solicitation. SWPC proposed a NGT concept that covers single gas turbine-based configurations in sizes from 70 MW to 200 MW in both simple-cycle (SC) or combined-cycle (CC) applications. Performance attributes of the NGT concept would be in line with those specified in DOE's RFP:

1. improved LHV net system efficiency of 15% or higher
2. 50% or higher improvements in turndown ratios
3. 15% or higher reduction in the cost of electricity
4. improved service life
5. reduction of emissions (carbon and NOx)
6. 15% or higher reduction in operations, maintenance and capital costs
7. flexibility of at least 400 starts per year
8. improvements in reliability, availability, and maintainability (RAM)
9. the capability to use multiple fuels.

In furtherance of that contract, PA Consulting Group was awarded a subcontract by SWPC to assist in the evaluation of the market prospects for SWPC's proposed NGT concept. To do so, SWPC asked PA Consulting to characterize the future power market environment over the 2007-2020 period in six key target markets (KTMs):

- the United States (including a breakdown by key region)
- five international markets: Brazil, Mexico, Germany, Italy and Spain.

These five countries were selected since they represent a suitable cross-section of potential markets. The time period of 2007-2020 was selected since the new NGT technology was assumed to be available for orders by 2006 (for start-up in 2008-2009).

Within this overall framework, PA Consulting was asked to assist SWPC in characterizing the market potential for its NGT concept by carrying out twosteps:

- Step 1: Characterize the Likely Future Power Market Structure and Demand Evolution in each KTM
- Step 2: Assess the overall Market Potential in each KTM

This report presents the results of both steps. Step1 involved three substeps.

1. A characterization of how each KTM is likely to evolve during both the baseline period and the early part of the competitive phase (roughly through 2010). This characterization focused on:

    - Extent of deregulation/privatization (including the extent of wholesale power market development, the level of market liquidity, the types of prevalent power bidding market mechanisms, and the likely structure of the population of competitors)
    - Environmental regulations (and their potential impacts on the competition between coal- and gas-fired capacity)
    - Other external factors affecting power generation (political actions related to nuclear power, social opinions (NIMBY), etc.)
    - Energy prices.

2. A projection of demand growth and CC/SC capacity additions over the 2001-2006 period to establish the baseline market environment the SWPC NGT concept will face when introduced.

3. A projection of demand growth and aggregate capacity requirements over the 2007-2020 period after taking into account the status of each KTM in 2006, as determined in substep 1 and each KTMs likely evolution as characterized in substep 2. in addition, we projected the potential range of SC/CC capacity additions during that period.

Step 2 called for providing our assessment of the potential market size for gas turbine (GT) capacity additions in six types of CC/SC applications in each KTM over the 2007-2020 period:

- Pure power generation (either merchant or regulated) owned by power producers
- Industrial cogeneration (including self-generation and third-party owned plants)
- Combined heat and power (for self- or third-party-owned commercial or institutional sites)
- Repowering (of existing oil-, coal- or gas-fired power plants) owned by power producers
- Integrated Gasifier Combined Cycle (IGCC) owned by power producers
- Distributed generation (over 30 MW) for local applications and owned by regional distribution companies or energy retailers.

For each of these applications, PA was asked to characterize the market drivers that will motivate customers to consider these applications, the GT size range and mean expected to serve these applications and the expected percentage (%) of the market by duty cycle for each application for each KTM. To that end, SWPC provided a matrix format to compile the various estimates required.

In addition to filling that projection matrix format, PA was asked to discuss the drivers specific to two markets (the first for CCs and the second more for SCs):

- Pure Power Generation and IGCC. The equipment configuration for these applications will vary from multiple gas turbines to different combinations of gas turbines and steam turbines for a given total MW plant size such as 2 gas turbines-1 steam turbine vs. one gas turbine -1steam turbine. The study discusses how these decisions will be based not only on the technology's economics, flexibility, and reliability but also on local market conditions (including price volatilities, grid stability and system congestions) and plant owners' management approaches.
- Duty Cycle. In peaking duty operation and some intermediate duty operation, the starting time to provide power to the electrical grid is a significant concern to some customers. The study discusses how this market driver affects selection of equipment and market direction for meeting customer needs in the future

SWPC will use the market driver and duty cycle information to develop a set of product features for each application, with the intent to develop a product/technology roadmap. In the following chapters, we present our findings for each of the six KTMs. Specifically, for each KTM, we discuss:

- the market's evolution, display our projections for the 2001-2006 baseline period, and outline our estimates of projected demand growth and capacity requirements over the NGT competitive phase (2007-2020)
- the future market for CC/SC applications in the six specific power applications in each KTM
- the amount of GT capacity additions involved, given the relative mix of CC/SC capacity additions in baseload, intermediate and peaking (BIP) applications
- the size distribution of GT capacity additions in these applications (with estimates of low, high and average GT sizes as well as estimates of the fraction of GT capacity that may fall below 150 MW or below 200 MW).

1.1 SUMMARY FINDINGS

We project a total of 304 GW to 476 GW of CC/SC capacity additions in the six KTMs over the 2007-2020 period. This includes between 223 GW and 335 GW in the United States and between 81 GW and 141 GW in the five other KTMs.

We also estimated that the mix of CC/SC capacity additions would be 33% baseload, 35% intermediate, and 32% peaking. Interestingly, this BIP mix is quite similar in both the US and abroad. However, this similarity stops there since there are differences in BIP mix among US regions and between countries:

- In the US, the Southeast shows the highest relative baseload need (38%) while the lowest needs are found in the Northeast and the Midwest. This difference is due to the fact that the Northeast is likely to show the highest intermediate needs (52%) and the Midwest the highest peaking needs (37%). The West will also show high peaking needs (37%).

- Mexico shows the highest relative baseload duty usage (44%) followed by Italy (38%) while Brazil has the lowest usage (26%). In addition, Germany and Brazil have the highest fractions (41% and 40%, respectively) of intermediate duty usage. Finally, Italy and Brazil have the highest peaking need usage (36% and 35%, respectively).

In the United States, the mid-case demand for gas turbines was forecasted at 212 GW. The largest demand was found in the Southeast (defined as the combination of SERC, FRCC and SPP) with potential GT additions of 78 GW (37%), followed by the Western Region (WSCC) with 56 GW of potential GT additions (26%) and the Midwest (defined as the combination of ECAR, MAIN and MAPP) at 40 GW (19%).

Abroad, the opportunities for GT capacity additions are fairly even among the five KTMs that we analyzed since the largest potential was found in Mexico at 21 GW and the lowest in Germany at 14 GW. Our estimates for other countries are very close to each other: 17 GW in Brazil and Spain and 15 GW in Italy.

In terms of projected GT capacity additions, pure power generation dominates by far overall with an estimated 64% share of all projected capacity additions in all six KTMs. This is followed by industrial cogeneration (11%), repowering (10%), decentralized generation (7%), IGCCs (5%) and CHP (3%). There are some differences in terms of this mix between the US and the non-US KTMs. In the US, the share of pure power generation is lower (61%) vs. 70% abroad; the difference in the U.S. is made up by a larger industrial cogeneration share (13% vs. 9%) and a higher IGCC share (6% vs. 3%). The share of repowering or decentralized generation are quite similar, however.

Next, we looked at the size distribution of CC and SC projects. Regarding CCs, we concluded with three CC project size projections relevant to that period:

- An increasing number of projects will fall in the 600-800 MW category – the associated capacity share will average 25%
- A growing share – up to 20% - of the announced capacity will involve projects in the 900-1100 MW
- About 27% of the project capacity will involve projects above 1,100 MW –out of that, 15% will be in sizes between 1,100 and 1,200 MW and another 10% will be between 1,200 MW and 1,500 MW.

Regarding SCs, we believe that a higher share of SC projects (up to 50%) will in the future fall in the 600-900 MW as the demand for 700-800 MW size projects will increase.

Based on that information, we assessed the likely size distribution of future GT additions in CC/SC capacity additions between 2007 and 2020. We found that four applications (i.e., pure power, IGCC, repowering and industrial cogeneration) would require in the 2007-2020 period average GT sizes above 200 MW while the remaining two others would be characterized by average GT size of 84-102 MW. More specifically, we found that the average sizes for various applications would be:

- 219 MW for pure power generation (225 MW in the US and 202 MW abroad)
- 185 MW for industrial cogeneration (199 MW in US and 162 MW abroad)

- 91 MW for CHP (83 MW in the US and 105 MW abroad)
- 242 MW for repowering (248 MW in the US and 228 MW abroad)
- 267 MW for IGCCs (277 MW in the US and 254 MW abroad)
- 83 MW for distributed generation (84 MW in the US and 78 MW) abroad.

In general, we find that the US would tend to require both larger and smaller units than the other countries. Among the non-US countries, a similar observation can be made among the European countries that would also tend to require larger average GT sizes than either Mexico or Brazil.

However, as one can readily guess, there are quite some differences among the non-US KTMs. For example, some applications have much more potential in some countries than others:

- the highest potential for pure power generation is found in Mexico
- the share of industrial cogeneration applications is high in both Brazil and Mexico
- the highest potential for repowering was projected to be found in Italy and very limited repowering opportunities are likely in either Brazil or Mexico
- IGCC prospects are the highest in Germany, Italy and Spain
- Distributed generation additions are the highest in Italy and Germany.

These differences can in large part be explained by the similarities that we found among the three more mature KTM electricity markets in Germany, Italy and Spain while the electricity markets in both Brazil and Mexico are much more in their formation phase.

However, we also found some differences across US regions.

- the highest potential for pure power generation is found in the Southeast and the West
- the share of industrial cogeneration applications is the highest in the Southeast
- the highest potential for repowering was projected to be found in the Midwest and the Northeast
- IGCC prospects are found in the Southeast and West regions
- Distributed generation additions are the highest in the Midwest (otherwise fairly evenly split across other regions).

We also assessed the share of the GT capacity additions that would fall below the 150-MW and 200-MW thresholds. In our estimation, we found that:

- 97 GW would be below 150-MW (64 GW in the US and 33 GW abroad)
- 171 GW would fall below the 200-MW threshold (114 GW in the US and 57 GW abroad).

This implies that the NGT concept could - sizewise - address between 33% and 57% of all projected GT capacity additions in the six KTMs: more specifically, between 30% and 54% of the GT capacity in the US and 39%-66% of GT capacity additions projected abroad.

Although on the margin, the NGT may compete with improved machines (e.g., 7A-type) or even new machines (H-type generation or even a larger size Vision-21 type turbine), it will be uniquely suited to address some specific applications. It will also be a good candidate to replace some of the older cycling capacity in most KTMs.

The assumed added flexibility of the NGT concept will be particularly well received because it will help future power generators to manage their production revenues most efficiently. We found that these players will want to manage their generation activities on a portfolio basis and as such they will like the NGT features to

- "round-off" their power generation portfolios
- allow them to manage excess power sales
- pursue repowering
- fill serious needs in distributed generation.

In addition, the NGT will be able to compete well against an increasingly less efficient intermediate cycling base in most of the KTMs that we have addressed in this study. That base will consist of coal-, oil- and more and more gas-fired units toward the end of the NGT competitive period (e.g., past 2015).

We also attempted to assess, as requested, the future comparative merits value of a 2x1 vs. 1x1 NGT configuration as well as the value of a rapid ramp up for GTs. Our analysis remained generic in nature since we did not conduct interviews with generators. Furthermore, it remains quite difficult to extrapolate how both future power markets and future power generators will behave. However, in the following, we have relied on the work that we conduct for many power players, carrying out a multitude of plant investment evaluations and merchant power market analyses.

Our analysis also indicates – at least on a preliminary basis, within the scope of this effort – that a 2x1 configuration will tend to be more used – possibly capturing 65% of the NGT capacity that could develop in CC configurations. This is predicated on the basis that such 2x1 configuration offer the equivalent of a $25-40/kW benefit. We also conclude that a 2x1 configuration would be most appropriate in the following NGT-addressable situations:

- highly-volatile markets (which could make up about 20% of the entire six-KTM market) – the cycle can better respond
- during cycle-transition times (during which could be installed an estimated 40-45% of the projected GT capacity over the 2007-2020 period) – the unit could be built in stages
- load-following industrial cogeneration, CHP and repowering projects (better load match)
- decentralized generation.

We also concluded that a 2x1 configuration would benefit from a faster 20-25 minute start-up, adding another $10-15/kW benefit. Likewise, SCs with, say, a 8 minute faster start-up would enjoy the equivalent of a $12-18/kW benefit.

Overall, the NGT has a potential role in the admittedly increasingly crowded future spectrum of power prime-mover solutions. Taking all our findings into consideration, we would estimate that a NGT should be able to address with sufficient differentiation a GT capacity need of 60-110 GW in the six KTMs considered, including between 40 and 80 GW in the United States.

1.2 SUMMARY APPROACH

In assessing the market in each KTM, we proceeded with a systematic 9-point approach:

- First, we reviewed the market trends (pace of deregulation, demand growth, reserve margins, environmental considerations, project announcements, industry structure)
- Second, we considered the characteristics of the current load curve
- Third, we looked at current volatility prices and considered how market price dynamics may change through the transition period
- Fourth, we analyzed the size distribution of current project size announcements
- Fifth, we considered how the supply curve could change through the transition period (up to 2007)
- Sixth, we drew implications on the size distribution and baseload, intermediate and peaking (BIP) power mix of future plants in various CC/SC applications
- Seventh, we considered possible technology developments in terms of new GT models or new CC sizes
- Next, we estimated the amount of projected GT capacity additions involved with each CC/SC application, given the estimated BIP mix
- Finally, we projected a size distribution profile for GT capacity additions associated with each CC/SC application type – including estimates of the fraction that is likely to involve GT units below 150 MW or 200 MW.

In developing estimates of GT size distribution, we used a six-bin GT size segmentation with GT units below 50 MW; between 50 MW and 100 MW; 100-150 MW; 150-200 MW; 200-300 MW; and over 300 MW. That last category was designed to reflect the likelihood of even larger turbines being commercialized past 2010. A maximum size of 360 MW was chosen for that purpose.

Exhibit 1.1 - Market Prospects Summary (2007-2020) for All KTMs (U.S. and non-U.S.)

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	205	292	21%	36%	44%	*30*	*360*	*219*
Industrial Cogeneration	32	57	63%	35%	3%	*30*	*360*	*185*
Combined Heat and Power	9	17	24%	53%	23%	*30*	*200*	*91*
Repowering	28	52	68%	32%	0%	*100*	*360*	*242*
IGCC	13	23	94%	6%	0%	*150*	*360*	*267*
Distributed Generation	17	36	13%	39%	48%	*30*	*150*	*83*
TOTAL	**304**	**476**	**33%**	**35%**	**32%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Overall GT Capacity Share (%) <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	200	52	105	26%	53%	17%	35%
Industrial Cogeneration	29	13	20	45%	69%	4%	7%
Combined Heat and Power	9	9	9	96%	100%	3%	3%
Repowering	26	2	11	6%	44%	1%	4%
IGCC	12	0	3	0%	22%	0%	1%
Distributed Generation	22	22	22	100%	100%	7%	7%
TOTAL	**297**	**97**	**171**	**33%**	**57%**	**33%**	**57%**

Source: PA Consulting

2. MARKET DRIVERS

In this chapter, we discuss how we expect power generators in the future to make decisions regarding the type of power generation system that they need and wantto invest in, with a focus on combined cycle (CC) and simple cycle (SC) applications.

We first discuss what are the factors that will determine the characteristics of future power generation markets – including market dynamics, technical and regulatory factors. Second, we discuss how these factors will influence future power generators when they are called upon to decide which CC and SC system size, plant configuration and ramp up capability they want.

2.1 FACTORS OF CHANGE

The characteristics of the future power generation markets in the United States and the various KTMs considered in this study will be affected by several key dynamic variables:

- Changes in local power supply curves. These curves profile the amount of capacity that can bid at a given wholesale power price. The shape of these curves will greatly change between now and 2020 as substantial amounts of gas-fired capacity gets added in each KTM country. First, gas-fired capacity will account for over 90% of all projected capacity additions in the six KTMs. Second, gas-fired capacity additions can technically cover the entire baseload, intermediate and peaking spectrum (as opposed to nuclear that is typically baseload, coal that can be baseload/intermediate and wind that is peaking)
- Changes in local market governance and operating rules. In many KTMs, experience with fully deregulated markets remains quite limited. Market rules are thus likely to be modified to adjust to unforeseen competitive developments.
- Changes in power generator asset portfolio management approaches will occur. Many countries will see the emergence of large merchant power companies that will seek to optimize their assets.
- The availability of sites will affect size choices based on land availability, absolute environmental emission standards, water availability, and fuel access
- Plant transmission constraints and congestion pricing can allow some smaller plants to be attractive as they trade flexibility for economies of scale
- There will be an increasing number of spun-off distribution companies which will want to invest in local production means of 30 MW or more (even up to 150 MW) to adjust their needs and protect themselves against power availability constraints or price gyrations
- Wholesale power providers will start to migrate toward retail activities as retail markets progressively open in the various KTMs. These providers will then program the evolution of their asset portfolios so as to satisfy more complicated load requirements. By the same token, they will become more sensitive to specific local delivery conditions, and consider the addition of smaller (DG-like) plant additions.

- Distributed generation (DG) below the 30 MW threshold level will grow. End-users, energy service companies, specialized project developers or power generators, local distribution companies, trading companies, municipalities and cooperatives and even larger wholesale generators are likely to invest in DG means as their economic and technical characteristics continue to improve. An increase in DG capacity additions can trigger a reduced demand for mid-size (especially simple-cycle) plants.

In the following, we discuss the main points.

2.1.1 Changes in Local Power Supply Curves

Local (i.e., country or region-specific) power supply curves will change over time as the result of several factors. By far, the most important one is the forecasted addition of substantial amounts of gas-fired CC and SC capacity that will tend to have a double effect:

- It will reduce ("clip") the average bidding cost of the most expensive "peak" tier of plants
- It will extend and flatten the "intermediate/baseload" part of the curve.

To illustrate these points, we show in Exhibits 2.1 through 2.3 the anticipated changes in power supply curves in Germany, Italy and Spain. These changes are the most pronounced in Germany and Spain:

- In Spain, we estimate that 20% of the most expensive current power generation capacity will be fatally challenged. The result there will be a flattening and extension of the mid-plateau of the power supply curve, indicating that the average intermediate price will decrease by 20% and the volatility in peak prices will also decrease by 25% (although it will remain relatively high).
- In Germany, intermediate prices could drop even further (by up to 40%) and peak price volatility will be reduced by 30% (less high prices but affecting a larger fraction of the peak demand curve).

By comparison, changes to the Italian power supply curve are much less pronounced – the impacts on intermediate power prices are being forecasted to be lower (possibly 10% lower) but volatility could still remain high.

Both effects are likely to trigger power plant shut-offs as existing plants may find it difficult to compete with newer more efficient plants. Plant deratings will tend to amplify the problem and some owners may be constrained in their abilities to modify their existing capacity to make it more attractive. For example, they may find it too difficult to convert the energy source at some existing plants. Also some plants in urban areas may hit increasing environmental opposition and technical remedies to respond to new environmental requirements may become too onerous. These same factors may affect the extent to which there will be plant brownfield expansions.

At the same time, there may be changes in local market governance and trading rules that affect some assets more than others. Likewise, new environmental rules (e.g., Nox limits) may affect the dispatching or level/type of operations of one class of assets (e.g., cycling boilers) more than others.

Finally, plant capacity additions are likely to come and go in cycles. In several KTMs, the potential for two up-and-down cycles is quite high during the NGT competitive phase. These cycles may last between 2 and 5 years.

2.1.2 Changes in Market Governance

Even in the best case (i.e., the PJM system in the United States), there have been only 3 years of full experience and even there, rules changed significantly once. In other cases, this is even more an issue:

- In Spain, there has been a stable market operating for more than 3 years but this is not a true open market and a major change in market structure will occur in 2002-2003.
- In Germany, two exchanges have been operating for a period of slightly more than one year and changes can also be expected in 2002-2003.
- In Italy, the market will start this year and we can expect between 18 and 24 months before reaching stable governance (but the handling of retail issues will probably create further complications thereafter).

Future changes in governance are likely to have significant impacts:

- They will affect the market for ancillary services (in addition, secondary markets will probably develop for ancillary services as well)
- They will have to deal with the issue of load aggregation and the minimum size of power blocks that can be economically and effectively traded.
- They will accommodate shorter bid time frames (down from one-hour ahead)
- They will imply a higher level of demand-side bidding (DSB) representation. Estimates of DSB activity in the United States range between 20 GW and 50 GW, although it may be around 10-15 GW, more realistically. Future DSB will lower peaking needs in the first 3-4 years of activity; thereafter, the DSB potential may be largely tapped and peaking needs will be more sharply split between centralized units versus decentralized units.

2.1.3 Changes in Wholesalers' Management Approaches

Power generators will less and less evaluate new plants or plant changes on an individual plant basis but they will rather focus their evaluaton on how each new or altered plant can interact with the rest of their asset portfolio. At the same time, asset portfolios will tend to grow and become more diverse. Therefore, generators will increasingly have the choice to contractually combine the outputs from more and more various plants situated in more and more different locales to meet more and more various wholesale needs. In addition, as markets continue to deregulate, an increasing number of power wholesalers will want to serve retail loads – first, focusing on large industrial loads, then aggregating commercial or residential loads and eventually addressing smaller individual loads.

As wholesale power generators become more eager and able to address retail needs, they will look for more logistical (more local and more flexible) power generation means. They can do so through contractual means by, for example, acquiring output rights to local cogeneration plants or buying shares of regional peaking plants. However, some will want to protect themselves by investing in smaller central plants and possibly DG facilities.

Finally, increasing deregulation will also result in an increasing number of new distribution companies spun-of from incumbent integrated utilities. The rationale behind this is that the business models for power generation and power distribution are very different; therefore, the claim is that these two types of assets should be managed differently and separately. Most spun-off distribution companies are not likely to control power generation assets, yet they will have to serve their loads (regulated or not). To do so, they will want to invest in a minimum amount of asset protection. This has been the case in many deregulated markets – e.g., Argentina, Australia and Nordic European countries.

2.1.4 Impact of DG

There are many efforts to develop DG technologies that span the entire size spectrum from just a few kWs to 20 MW with the promotion of improved low-emission reciprocating engines with higher efficiencies, the rolling-out of microturbine technologies (currently in the 25-100 kW range but then increasing toward the 250-350 kW range), the development of fuel cells in the 5kW to 2 MW range, the development of Stirling engines, the promotion of hybrid fossil-wind or fossil-solar systems.

There have been many diverse projections about the potential for DG capacity additions. In general, these projections vary because:

- They do not always relate to the same consistent size spectrum. Some forecasts may focus on the micro-DG market (say below 100 kW while others may address the mid-market DG needs (say between 100 kW and 10 MW). In some cases, the forecasts are trying to be all encompassing and include all potential applications between the 5 kW level and up to 30 MW or 50 MW.
- They use various assumptions about DG technology and cost performance parameters. There are considerable uncertainties about the efficiency, part-load performance and capital costs of several DG technologies under development, most notably fuel cells but also, to a lesser extent microturbines and Stirling engines.
- They have different views on how quickly the DG market can penetrate the fragmented universe of residential, commercial, institutional and industrial applications – many of which are site-specific, subject to vastly different prevailing fuel and electricity rates and owned by end-users with a wised range of technical and economic needs.

A review of various DG forecasts will show possible DG contributions that could vary between 5% and 20% of the capacity additions projected over the 2007-2020 time period across all six KTMs.

In the United States, for example, estimates of average annual DG capacity additions below the 30 MW NGT threshold during the 2007-2020 period, have varied between 800 MW and 2,000 MW. Likewise, annual DG estimates below 30 MW for other KTMs have generally ranged between 250-300 MW and 800-1,200 MW per year across the three European KTMs.

This level of potential below-30 MW DG development means lower overall centralized capacity additions plus a reduction in the amount of local generation resources (especially mid-size industrial cogeneration, CHP and above-30 MW decentralized generation). To illustrate this point, our U.S. forecast assumes 20 GW of below-30 MW DG over the 2007-2020 period.

2.2 IMPACTS ON THE SIZE DISTRIBUTION OF WHOLESALE PLANT ADDITIONS

Before we can project the future size distribution of GTs, we need to discuss the future distribution of gas-fired CC and SC plants.

To address the latter point, we first analyzed plant data base announcement statistics. In doing so, we looked at CC and SC project announcements separately. We also looked at the US and non-US KTMs markets independently.

Regarding CCs, we found interesting project size distribution trends at three levels which we call the mid-1,000 MW level, the sub-1,000 MW level and the supra-1,000 MW level (see Exhibits 2.1 through 2.4).

First, an analysis of the size distribution of current gas-fired CC plant capacity addition announcements in non-US KTMS shows that there is a strong preference for plant additions around 400-500 MW (with 16% of all announcements) and 800-900 MW (with 26% of all announcements). Together, these two mid-1,000 MW and sub-1,000 MW peaks make up about 56% of the announced project capacity in projects below 1,000 MW. The next most popular project size is the 700-800 MW category with 10% of all announced project capacity (14% of the project capacity below 1,000 MW). In addition, we find that a fairly large share (26%) of projects are announced with sizes above 1,000 MW.

This compares with the US where we found that a larger share (35%) was associated with projects over 1,000 MW. We found that 12% of the announced capacity involves projects between 1000 and 1100 MW and another 8% is associated with projects between 1100 MW and 1200 MW. Together, 20% of the announced capacity is in project sizes between 1000 MW and 1200 MW. However, we also found another 16% in sizes between 1200 MW and 1800 MW. Clearly, the US supra-1,000 MW peaks are much higher (by 20% or more).

Below the 1,000-MW threshold, we also found that the most popular project sizes in the U.S. were also larger than abroad. The most popular U.S. size is 500-600 MW with a 23% capacity share - compared to a 7% share for non-US KTMs where the mid-1,000 MW peak is found in the 400-500 MW size category below with a 26% share).

The reverse seems true at the sub-1,000 MW level. The next most common size ranges in the US are 800-900 MW (11%) and 600-700 MW (11% as well) – compared to 26% and 4%, respectively, abroad. However, this is because the proportion of US projects just above 1,000 MW is also much higher.

Interestingly, when we look at the size distribution of preliminary CC projects abroad, we also find that there is a trend toward larger projects to the extent that the data indicates a preference for projects between 900 and 1000 MW as opposed to 800-900 MW for CC projects already under development.

The data thus indicates a general trend toward larger and larger CC projects:

- A migration from the 400-600 MW band to the 500-800 MW size band
- A shift from the 800-900 MW size category to the 900-1,100 MW size band
- A higher share of projects above 1,000 MW.

In our estimation, this CC project size trend is likely to continue in most non-US KTMs to the point that it may approach the current U.S. project size distribution, especially as those KTMs open up to true wholesale deregulation. For example, we can already observe that the size distribution of CC projects in both Spain and Italy have changed over the past 18 months and are now featuring significant capacity increases in both the 800-900 MW project size category (over 30%) and the supra-1,000 MW size band (now in excess of 27%).

In the US, however, we can expect some delays, cancellations and slowdown in project announcements as discussed in more detail in Section 3 of this report. Thus, we would expect to see some regression toward somewhat smaller CC projects.

At the same time, we need to take into account the frequent signs that show a limit to the number of large baseload and intermediate projects. This is probably the most true for nuclear plant projects around current load centers or plants. For example, Entergy has already made claims that the addition of 1,000 MW nuclear plant blocks around existing U.S. nuclear power sites could be quite difficult to absorb in local wholesale power markets. For that reason, several U.S. electric utilities are looking at modular nuclear plants (using for example the Pebble-bed modular approach or the AGT route). In addition, many of the repowering opportunities that were targeted by purchasers of divested utility assets in the United States did not take place because the local markets were not deep enough at the time or because of permit restrictions.

Looking forward, the size distribution of future CC plants will be influenced by four factors:

- What turbine suppliers offer. In our dealings with power generators, they can be flexible to some degree on output size but they will also try to compare various offerings along the same reference plan output level. Generator size preferences will thus be impacted by turbine suppliers' trend to achieve higher and higher outputs from their turbine models.
- The appetite of certain wholesale power generators for local market shares. We find that there is a tendency to build the largest project possible because this tends to capitalize on economies of scale – both in terms of hardware costs but also soft project costs, including transactional costs. However, the sizing of projects is increasingly now a joint decision between project developers and power originators and traders. The later have an important say in judging the amount of power that the local market can bear – taking into account not only local demand growth but also the likelihood and profile of concurrent competitive project additions.
- The ability to ship/trade power on a larger geographic scale. Such ability will increase as power exchanges merge and thus offer larger economies of scale. In addition, the creation of larger power regions (e.g., through the RTO process in the United States) will favor this trend as well.

- The ability to develop hybrid plants that can not only bid in the local wholesale power markets but also can sell power to eligible retail customers. Over the past five years, we have witnessed an increasing number of such projects in Spain, Italy, Mexico and Brazil. In most cases, the fraction of the plant load sold to eligible retail customers accounted for 30-45% of the total plant output This trend may however decrease once we have reached some geographic market saturation, due to the limited number of industrial load clusters.

Overall, based on our trend analysis, taking into account the current schedule for deregulation across the KTMs, and considering that each KTM will probably experience a couple of up-and-down cycles during the 2007-2020 period, we conclude with three CC project size projections relevant to that period:

- An increasing number of projects will fall in the 600-800 MW category – the associated capacity share will average 25%
- A growing share – up to 20% - of the announced capacity will involve projects in the 900-1100 MW
- About 27% of the project capacity will involve projects above 1,100 MW –out of that, 15% will be in sizes between 1,100 and 1,200 MW and another 10% will be between 1,200 MW and 1,500 MW.

Regarding SCs, we find that 76% of the announced SC capacity in the U.S. involves projects between 300 MW and 900 MW. The most popular size category is by far 600-700 MW (22%) followed by the 800-900 MW category (17%) and the 500-600 MW category (15%). By extrapolation, we believe that a higher share of SC projects (up to 50%) will in the future fall in the 600-900 MW as the demand for 700-800 MW size projects will increase.

2.3 IMPACT ON FUTURE WHOLESALE PLANT BUYING CRITERIA AND DECISION-MAKING

We were asked to provide insights into the likely type of decision-making behind two types of choices that future power generators will tend to face as they make investments:

- The choice of prime-mover configuration for a given plant size –namely, the choice between a "2x1" (2 GTs for one steam turbine) configuration or a "1-1" (1 GT and 1 steam turbine) configuration for a combined cycle
- The level of ramp-up capability for a new gas-turbine technology to be used in both CC and SC plants.

We discuss each point below. Our analysis remains generic in nature since we did not conduct interviews with generators. Furthermore, for all the reasons mentioned before in this section, it remains quite difficult to extrapolate how both future power markets and future power generators will behave. However, in the following, we have relied on the work that we conduct for many power players, carrying out a multitude of plant investment evaluations and merchant power market analyses.

2.3.1 Configuration Decision-Making

To date, the 2x1 configuration has very much prevailed, accounting for the vast majority of the total CC capacity installed in the past 5 years. However, we have to recognize that most suppliers do offer several 1x1 configurations. There are also cases where power generators decide to install twin 1x1 cycles. Finally, there is also a trend toward the development of larger and larger 1X1 configurations. For example, General Electric's H-configuration is based on a 1X1 design but it has two versions (i.e., a single shaft one with one generator and a double shaft with two generators).

In the future, the choice of a 2x1 versus a 1-1 configuration for a combined cycle will depend not only on the technical and operational trade-offs of 1 versus 2 unit configurations but also on two other important factors:

- The company's portfolio make-up and revenue management approach
- The behavior and volatility of local fuel and power prices (especially during peak price cycles).

It can also be affected by the value of ancillary services but we focus on that particular point in the next decision-making discussion about plant start-up characteristics.

We examine each factor first and then develop some estimates of what is at stake.

<u>Company Portfolio Management</u>

The first factor will be important but it is also the least amenable to analysis. Over time, power generators will try to better balance – and optimize - their portfolios to be able to serve both wholesale and retail markets. They will also seek to balance their generation portfolios both asset-wise and contractually to achieve technology and fuel diversification.

In fact, we estimate that over 80% of the projected GT demand in 2007-2020 in all six KTMs will stem from generally large and well-diversified power players. The balance will come from surviving incumbents in still partially deregulated markets and, in fully deregulated markets, niche specialized power generators that concentrate on certain types of assets (e.g., logistical). [1]

For these large diversified players, plant configuration decisions will be influenced by some general portfolio consideration:

- General management policies especially in terms of plant standardization, parts management, and long-term service O&M agreement considerations
- Their willingness to swap and "churn" part of their portfolios

---

[1] Of course, the time frame for this assumption will vary across KTMs: this may be the case in the US, Germany and Spain by 2007 but it may take 1-2 more years in Italy, 2-3 more years in Brazil and Mexico.

- The overall balance and optionality of their portfolios given their perceptions on market trends and how the local power supply curve and market governances will change
- Their growth objectives (both wholesale and retail) and their appetite for risk.

We believe that, in the U.S., the first two points will dominate in the near future but that the last two points will become more important later on – i.e., by the beginning of the NGT competitive phase.

The last point, in particular, explains why several U.S. power merchant players opted for a preferred configuration to be replicated as often as possible as long as they were in a phase of plant build up in various regional markets. However, for the next 4-6 years, many of these generators will tend to first churn their portfolios and second, follow more a "fill in" pattern to position new plants where they best fit their current portfolios. Some power merchants have also started to take a 2-supplier approach to diversify their procurement risks; the cost of that approach becomes lower as the size of the portfolio increases.

Past 2007, we expect that we will be in a new up-cycle in the United States and that U.S. generators will have streamlined and re-balanced their portfolios. They will also have learned a lot about wholesale power market dynamics in both up and down cycles. By then, the choice of a new plant size and configuration will be more a function of the overall portfolio profile and the aggressiveness of a player in a given market (whose size will have increased as regional markets tend to spread). As such, a U.S. power generator may have the choice between plants of different sizes even though the decision will still be that of optimizing the plant size at the regional level.[2] The same will apply to other KTMs.[3]

Our conclusion is that a power generator will not always compare investments of same sizes. We would argue that, until the wholesale power markets have matured nationwide and outside of strong up-cycles, investments of various sizes may be considered in 30-35% of the cases.

<u>Behavior and volatility of local fuel and power prices</u>

That second factor will be a function of:

- Demand-supply imbalance cycles
- Industry structure and market power considerations
- Market governance rules

---

[2] U.S. generators will still be far from being able to optimize their physical portfolio nationwide because of continued regional segmentation but they will optimize the financial performance of their portfolios across regions.

[3] In other KTMs, however, a nationwide physical asset management approach may be possible earlier (say by 2012 in Spain and by 2015 in Germany and Italy).

In general, one can say that the higher the volatility in fuel and power prices, the more interesting it may be for a power generator to have the 2x1 option to combine the output of two prime-movers rather than one:

- It allows it to achieve a higher reliability at times of high power prices –thus maximizing its revenue potential and lessening the risk of having to buy expensive power in case of outage
- It can take advantage faster of price spikes by operating one or two GTs independently from the steam turbine – the gain can be between 25 minutes and one hour
- It is more appropriate to vary the combined GT output and be able to respond to various wholesale or retail load fluctuations during the ramp up period (between 1 hr and 4 hr, depending on whether it is a hot or cold start)
- It may better complement the other SCs or CCs in the rest of the power generation portfolio
- It may allow the generator to build the plant in two stages in highly volatile times.

Nonetheless, even when we assume the same output size, the evaluation of the full incremental optionality of a 2x1 configuration will depend on:

- The exact configuration (number of generators, HRSGs and extent of HRSG co-firing)
- The other 1x1 configurations being considered (two single shaft twin units, two multi-shaft twin units, one large single shaft unit or one large multi-shaft unit).

In the following, we estimated what is at stake in pure power generation applications, which represent the larger part of the potential NGT potential. Our analysis assumed a pricing environment consistent with "average" U.S. market conditions across ECAR and PJM in past three years.[4]

Under these conditions, it would quite possible to find that the 2x1 plant would be able to start on average between 35 and 70 times more than the 1x1 new plant.

Under these assumptions, we find that the added optionality of a 2x1 configuration could be the equivalent of $20-35/kW assuming that both the associated fixed-cost O&M cost penalty and part-load performance penalty are less than 3% above that of the 1x1 cycle. Of course, these results will vary for various assumed levels of penalty combination (capital cost, O&M cost and part-load performance) and different market condition environments.

Estimating what is at stake

---

[4]This includes assumptions such as a fuel and power price environment characterized by mean-reversion coefficients of 0.3 and 0.16, respectively; price volatilities of 0.20 in power prices and 0.16 in fuel prices; and a correlation of 0.5 between fuel prices and power prices.

However, these volatility-related advantages (or options) cannot come at the expense of a 2x1 configuration that would be too expensive in terms of capital and O&M costs because of lack of economies of scale. In addition, land costs and environmental constraints may play a role. Finally, one should note that the cost premia of a twin 1X1 versus a 2X1 and versus a 1X1 – all with the same output – are likely to increase when that output decreases.

Based on our analysis, we believe that:

- The generators' abilities to capture the optionality of a 2x1 cycle will continue to depend on their operating capabilities and the quality of their revenue management (trading) strategies
- Conditions are likely to change sufficiently to say that a given power generator will not always opt for the same configuration. Instead, it may end up hedging and choose a balanced mix of configurations. In addition, if we assume that demand-supply imbalance cycles tend to repeat themselves every 4-6 years, there would be at least 2 cycles over the forecast period.
- Power generators will also be influenced by the offerings of the prime mover suppliers. Generators' choices will be influenced by pricing policies, prime mover availability and other commercial aspects.
- Finally, prime mover differences may be compensated by differences in the plant cycle or balance-of-plant considerations. Not all plants will have the same BOP design. For example, differences in heat recovery steam generator design (e.g., with different degrees of reheating) can more than offset a difference in prime-mover part load performance or O&M characteristics.

The last point needs expanding. There has been much progress in HRSG thermodynamic cycle optimisation but the challenge in the future may be more to improve the reliability, availability and maintainability of commercial offerings.[5]

For all these reasons, the pros and cons for a 2x1 versus a 1x1 configuration will also vary by application.

In pure power generation, a 2x1 configuration will make the most sense in uncertain and volatile markets. Most of the orders in the recent surge of CC capacity additions in the United States involved 2x1 configurations. However, we also believe that pure power generators –

---

[5] As suggested in a recent meeting of the HRSG User's Group Annual Meeting, as reported in the September /October 2001 issue of Power Magazine. It was, for example, pointed out that the use of higher steam pressures to increase heat recovery implies the inclusion of thicker pressure parts – which in turn "increases the susceptibility to low-cycle fatigue when cycling." In addition, supplementary firing in the HRSG unit calls for changes in material (e.g., in fins and in insulation material). Studies by Foster Wheeler have shown that the most critical HRSG components in terms of fatigue during startup transients are the headers and h-p drums, and their connections to thin-walled tubing and piping. In addition, HRSG designers and suppliers are still experimenting with new ideas, such as Alstom with its single-row harp approach or Innovative Steam Technologies, which is actively marketing its Once-Through Steam Generator (OTSG) technology.

with large enough portfolios - will also want to hedge and opt for a mix of 2x1 and 1x1 configurations. Overall, we think that about 65% of the CC capacity will involve 2x1 units.

In IGCC applications, the optionality offered by a 2x1 configuration will depend on the source of fuel (process or coal) and type of use (power only or cogen) but, in general, it will be lower than for any pure power application of the same output. The reason will be the assumed lower reliability and flexibility of the gasifier. In addition, multi-fuel industrial applications will add their own operating constraints. For all these reasons, the intent of an industrial IGCC operator is to pursue output stability (often through co-firing, utilization of surplus process steam or nitrogen injection for power augmentation).

Overall, the preference will be – in our opinion - for 1x1 configurations in about 65% of the total projected IGCC capacity especially since there will be instances of several 1x1 configurations. There will also be industrial applications with 2 or 3 parallel 1x1 trains to accommodate load fluctuations. However, some power-only IGCC applications could involve 2x1 applications if the configuration is sized to sell 25-30% excess power in markets where there is sufficient volatility. In our estimation, a 2x1 would fit possibly 25-30% of the projected IGCC potential.

In other applications, we believe that:

- industrial cogeneration, the choice of a 2x1 can be influenced by several additional factors – compared to a pure power application of similar output range:
  - First factor may be the type of fuel used (especially if there is some co-firing involved, using for example process-based wastes).
  - Second, the process load fluctuations will play a role; third, the size of the excess in power plant sizing. Overall, a 2X1 configuration will make the most sense when all three factors are met – co-firing plus fluctuating load plus excess sizing. Overall, we estimate that 30% of the capacity may involve 2x1 configurations.
- In CHP applications, the 2x1 would seem to have a natural hedge – however, these applications may be on average 2.5 times smaller and the capital cost premia of 2x1 configurations are thus higher. The capacity share of 2x1 may be around 40%.
- In distributed generation, the large majority of applications will be simple cycles.

Overall, we believe that there will be a balance of 2x1 and 1-1 configurations. The more fluid and less volatile the market, the better it will be to have a 1-1 configuration for a large generator adding a significant amount of capacity year after year. However the power market will continue to go through supply-demand and energy price cycles and we believe that generators will opt for 2x1 configurations in greater capacity amounts (60-65% capacity share).

2.3.2 Plant Start-Up Decision-Making

The next point to discuss is the issue of plant start-up. Generally speaking, as power markets become more volatile, generators find themselves having to dispatch their generation assets more often. How quickly they are able to do so can have quite a financial impact.

However, not all generation assets will be affected by starting time. For example, the industrial cogeneration market, the combined heat and power market, the baseload pure power generation market and the IGCC market will tend not to be. The focus is thus on peaking and intermediate pure power generation applications (about 55% of the total projected GT market across all six applications).

In pure power applications, a rapid start-up capability can:

- reduce the fuel consumption during dispatching
- allow to better meet wholesale and retail load fluctuations and thus offer more options to vary the contracted outputs
- maximize revenue potential during high-price periods
- better complement the rest of the power generation portfolio
- avoid having other less efficient units on standby.

In particular, a unit with a faster ramp-up will provide four benefits:

- less energy consumption during start-up phase
- additional margin during the gain in start-up time
- more opportunities to dispatch – even during short periods of time
- more flexibility to bid for ancillary services.

A faster ramp up can benefit both CC and SC cycles. The effect could be, for example, a reduction of 20 minutes for CCs and, say, 8 minutes for SCs.

Such reductions will increase the number of times that either type of cycle can be in the money at the right time. Because market volatility conditions are likely to change at least every 4-6 years due to changes in up-and-down price cycles, the merits of a faster ramp up need to be evaluated over a short 5-7 year period. It is also the period during which the heat rate deterioration would be small enough to assume full dispatchability and flexibility potential.

If we assume that a faster ramp up can add on average between 50 and 100 start times per year, the impact for a CC is the equivalent of a $10-25/kW benefit, assuming no undue O&M penalty.[6] Under similar conditions, the impact for an SC cycle could be estimated at $10-15/kW.

At the same time, we are reminded of some of the same caveats that we had in our previous analysis:

---

[6] Here again, this is based on market assumption parameters of the following type: a fuel and power price environment characterized by mean-reversion coefficients of 0.3 and 0.16, respectively; price volatilities of 0.20 in power prices and 0.16 in fuel prices; and a correlation of 0.5 between fuel prices and power prices.

- The generators' abilities to capture the optionality of a faster ramp-up capability will continue to depend on their operating capabilities and the quality of their revenue management (trading) strategies
- Power generators will be influenced by the offerings of the prime mover suppliers. Their choice will be influenced by pricing policies, prime mover availability and other commercial aspects
- Finally, prime mover differences may be compensated by differences in the plant cycle or balance-of-plant considerations. Not all plants will have the same BOP design. For example, differences in heat recovery steam generator design (e.g., with different degrees of reheating) can more than offset a difference in prime-mover part load performance or O&M characteristics.

2.4 OVERALL CONCLUSIONS

Our analysis shows that the NGT concept in sizes up to 150 MW or 200 MW could - sizewise - address between 31% and 51% of all projected US GT capacity additions and 36-68% of GT capacity additions projected abroad.

Although on the margin, the NGT concept will have to compete with improved machines (e.g., 7A-type) or even new machines (H-type generation or even a larger size Vision-21-type turbine), the NGT will be uniquely suited to address some specific applications. It will also be a good candidate to replace some of the older cycling capacity in most KTMs.

The assumed added flexibility of the NGT concept will be particularly well received because it will help future power generators to manage their production revenues most efficiently. We found that these players will want to manage their generation activities on a portfolio basis and as such they will like the NGT features to

- "round-off" their power generation portfolios
- allow them to manage excess power sales
- pursue repowering
- fill serious needs in distributed generation.

In addition, the NGT will be able to compete well against an increasingly less efficient intermediate cycling base in most of the KTMs that we have addressed in this study.

Our analysis also indicates – at least on a preliminary basis, within the scope of this effort – that a 2x1 configuration will tend to be preferred – possibly capturing 65% of the NGT capacity that could develop. This is predicated on the basis that such 2x1 configurations offer the equivalent of a $25-40/kW benefit. We also conclude that a 2x1 configuration would be most appropriate in the following NGT-addressable situations:

- highly-volatile markets (which could make up about 20% of the entire six-KTM market) – the cycle can better respond

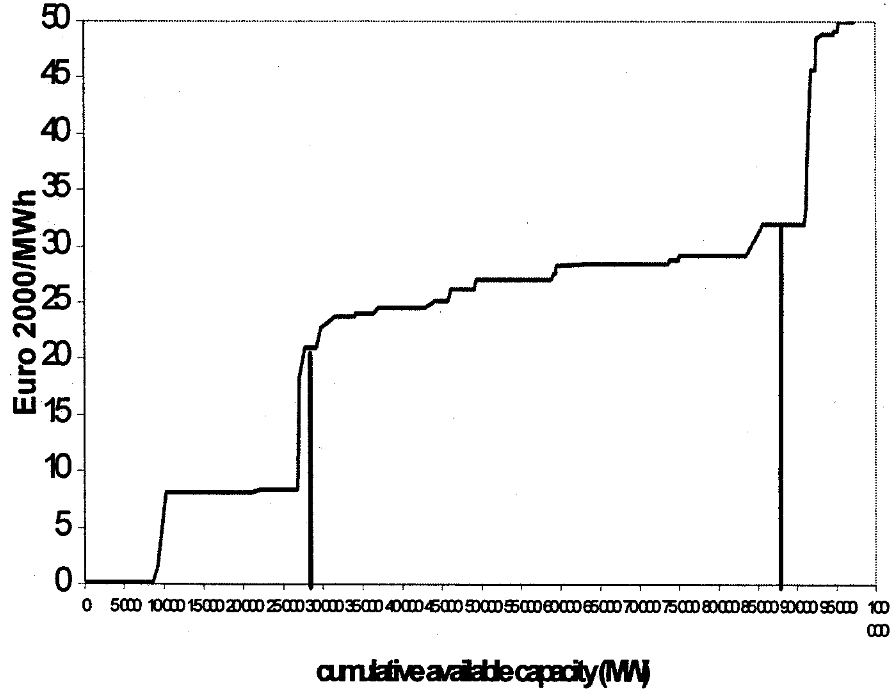
- during cycle-transition times (during which could be installed an estimated 40-45% of the projected GT capacity over the 2007-2020 period) – the unit could be built in stages
- load-following industrial cogeneration, CHP and repowering projects (better load match)
- decentralized generation, in large part by definition.

We also concluded that a 2x1 configuration that would benefit from a faster 20 minute-start-up, would gain another $10-15/kW benefit. Likewise, a SC application with a 8 minute-reduction in start-up time would have the equivalent of a $12-18/kW benefit.

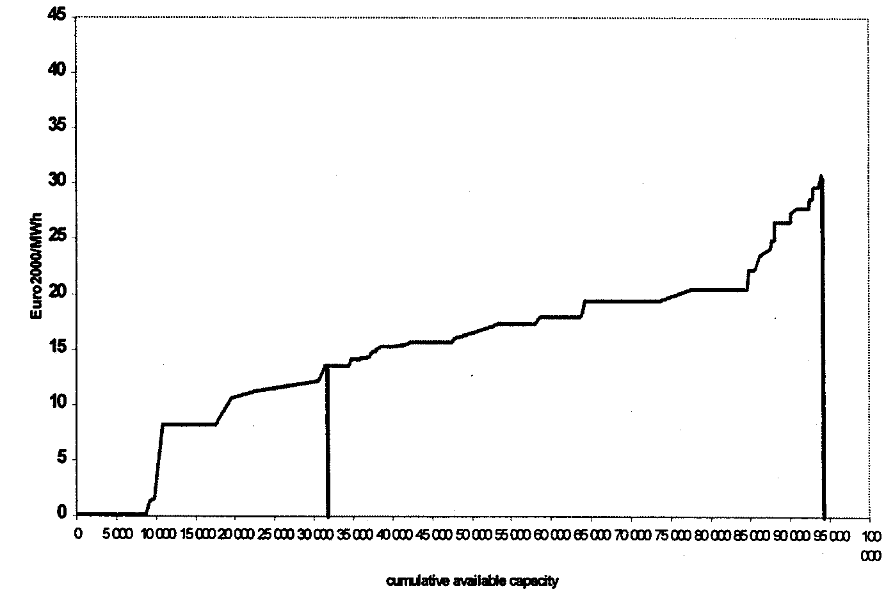
Overall, the NGT has a potential role in the admittedly increasingly crowded future spectrum of power prime-mover solutions. Taking all our findings into consideration, we would estimate that a NGT should be able to address with sufficient differentiation a GT capacity need of 60-110 GW, including between 40 and 80 GW in the United States.

Exhibit 2.1 – Projected Changes in Germany's Power Supply Curve

Now



2020

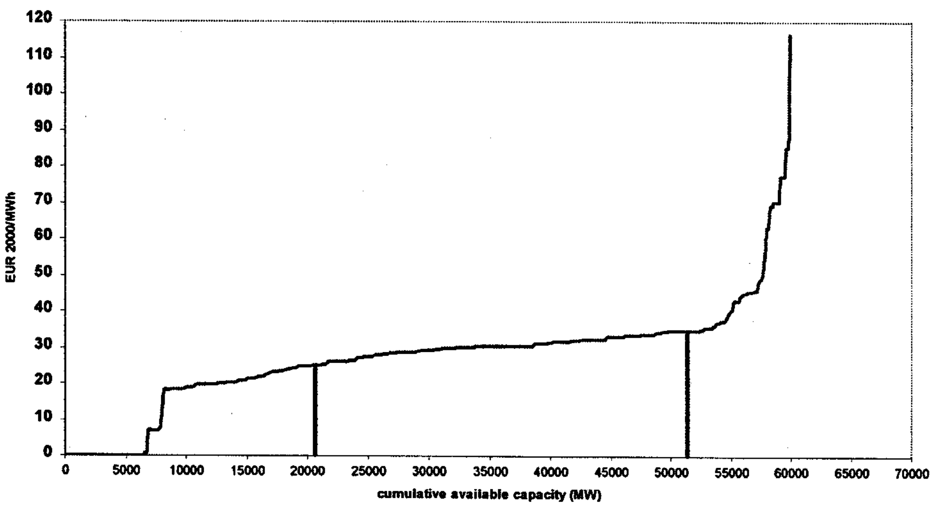


Source: PA Consulting

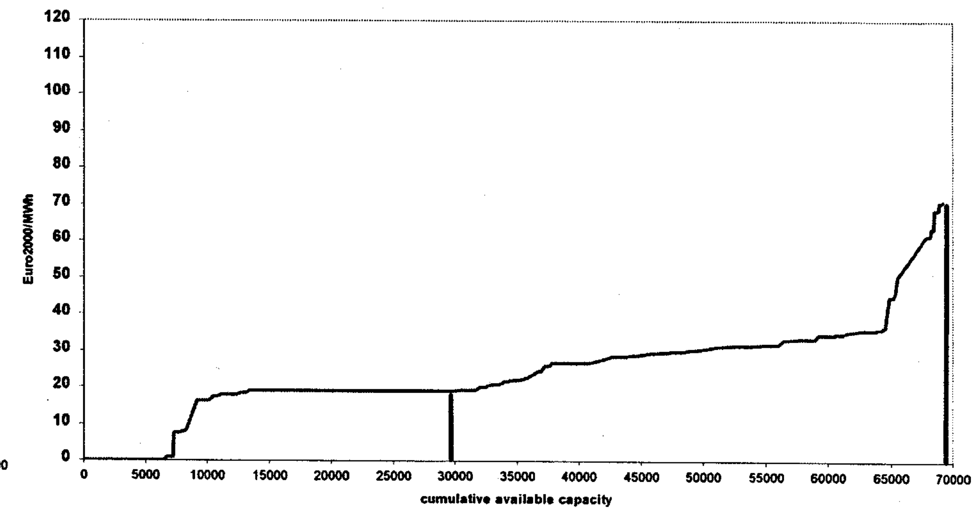
PA

Exhibit 2.2 – Projected Changes in Italy's Power Supply Curve

Now



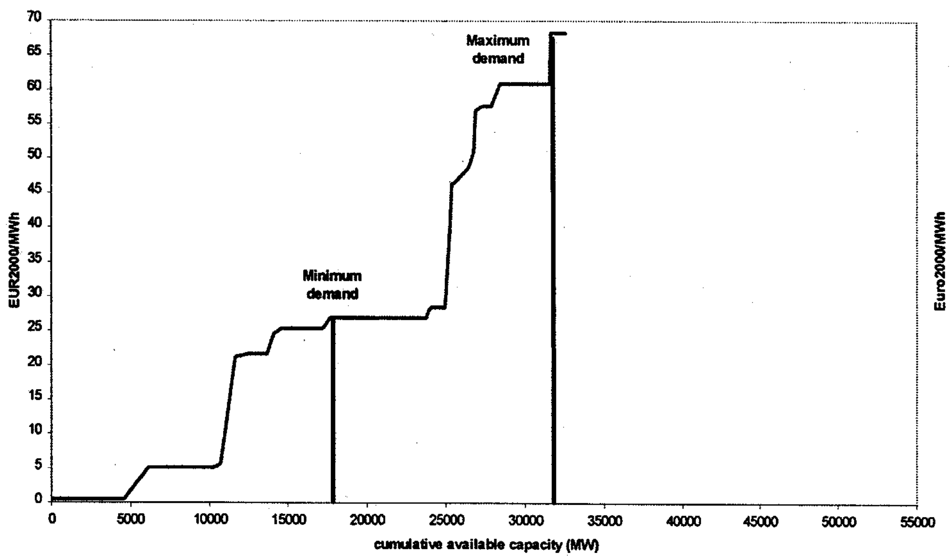
2020



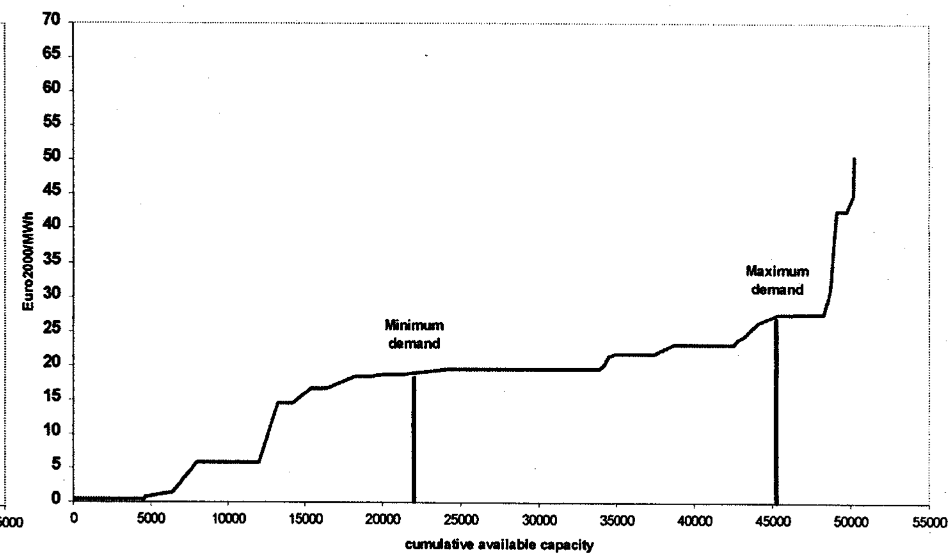
Source: PA Consulting

Exhibit 2.3 – Projected Changes in Spain's Power Supply Curve

Now



2020



Source: PA Consulting

PA

Exhibit 2.4 - Size Distribution of Natural Gas-Fired Combined Cycle Projects in all five non-US KTMS

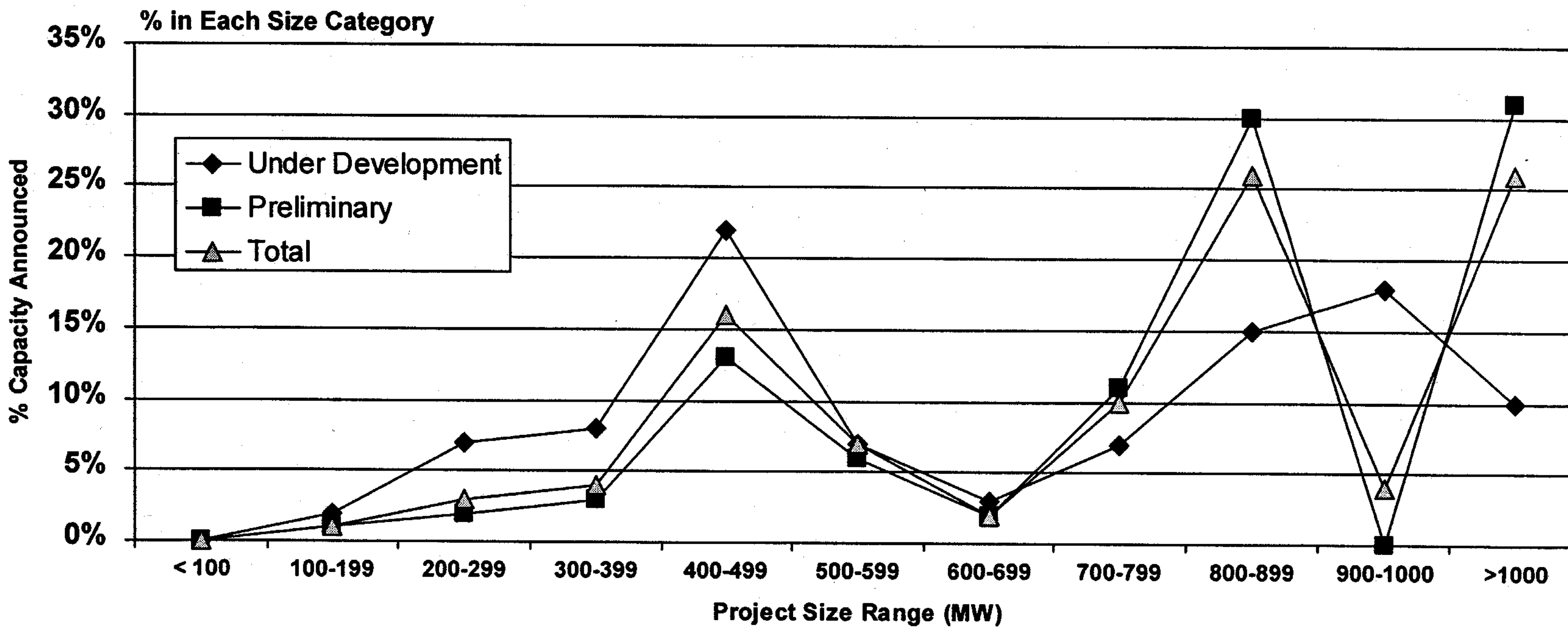


Exhibit 2.5 - Size Distribution of US-based CC Projects

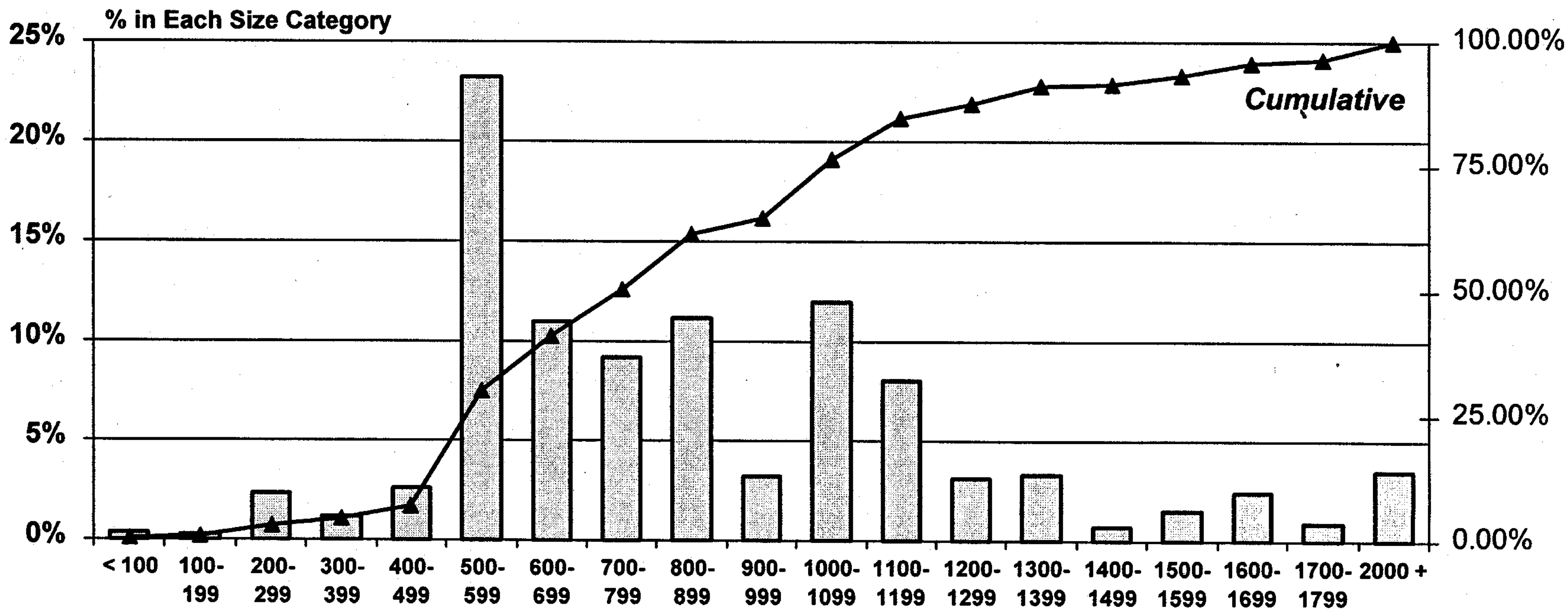
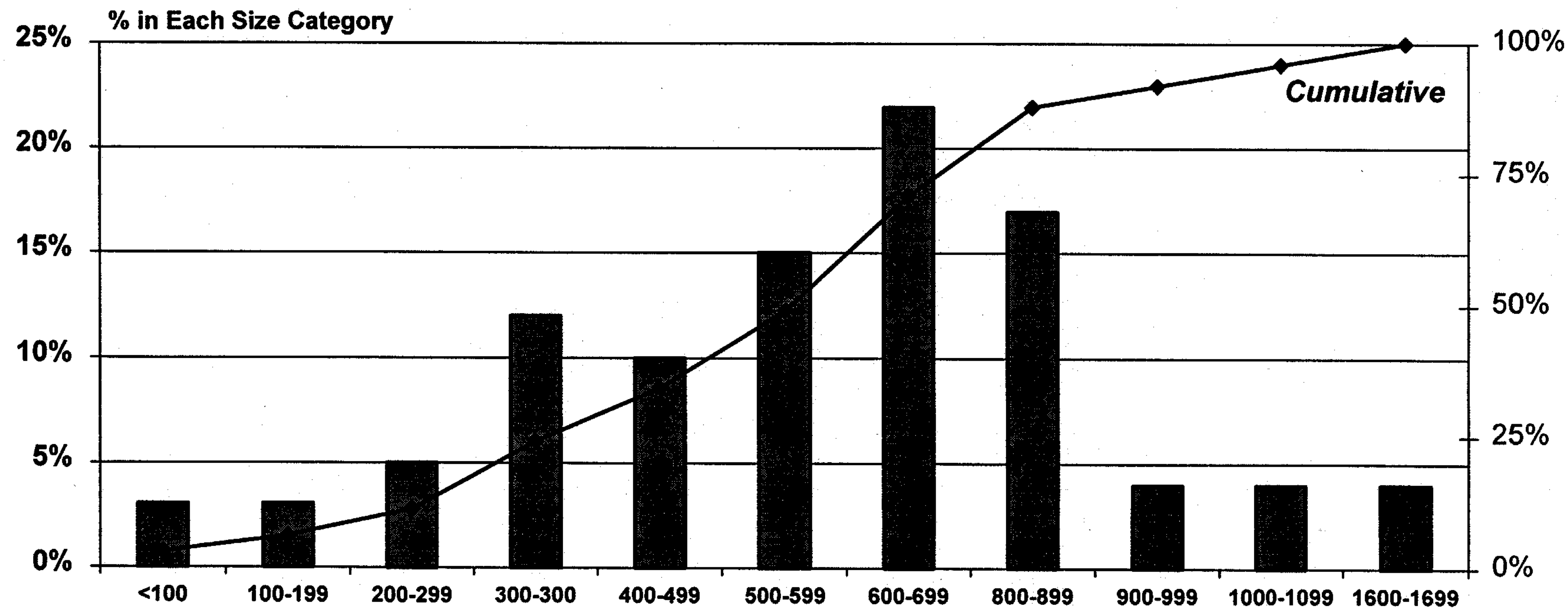


Exhibit 2.6 - Size Distribution of US-based CT Projects



3. U.S. OUTLOOK

In this chapter, we discuss the outlook for the U.S. power market. We focus on the U.S. market as a whole during both the baseline period (2001-2006) and the NGT competitive phase (2007-2020). We then discuss key differences among regions.

Our regional observations are organized both along the current nine NERC regions and the new five regions that are likely to emerge toward the transition between the baseline period and the NGT competitive phase. These five new regional blocks are:

- Northeast-MidAtlantic (NPCC and MAAC)
- Midwest (ECAR, MAIN and MAPP)
- Southwest (ERCOT)
- Southeast (SERC, FRCC and SPP)
- West (WSCC).

Next, we characterize the future US market over the 2007-2020 period for six applications:

- Pure power generation
- Industrial cogeneration
- Combined heat and power
- Repowering
- IGCC
- Distributed generation (over 30 MW)

We conclude that the US market could require between 260 GW and 378 GW of capacity additions over the 2007-2020 period, out of which we expect between 215 GW and 322 GW of gas-fired capacity additions. Adding between 8 and 13 GW of IGCC capacity, the total amount of gas-turbine-base additions is projected to range between 223 GW and 335 GW (as shown in Exhibit 3.1).

Over the 14-year timeframe, we forecast an even mix of base, intermediate and peaking needs (33%, 35% and 32%, respectively), but this is the composite result across the five market regions where BIP mixes are quite different (in spite of the larger size assumed for these regions):

- The Southeast shows the highest relative baseload need (38%) while the lowest needs are found in the Northeast and the Midwest
- The Northeast shows the highest intermediate needs (52%)
- The Midwest and West regions show the highest peaking needs (37%).

If we now focus on a mid-case situation, we find that the anticipated mix of simple and combined cycles that these BIP mixes are likely to entail results in a forecasted need for 212 GW of gas-turbine capacity additions over the 2007-2020 period.

Next, we looked at the size distribution of these GT additions. We found that four applications (i.e., pure power, IGCC, repowering and industrial cogeneration) would require in the 2007-2020 period average GT sizes above 225 MW while the remaining two others would be characterized by average GT size of 85-90 MW. More specifically, we found that the average GT sizes for various applications would be:

- 225 GW for pure power generation
- 199 GW for industrial cogeneration
- 83 GW for CHP
- 248 GW for repowering
- 277 GW for IGCCs
- 84 GW for distributed generation.

We further estimate that, in our mid-case, this level of gas turbine additions should create the need for 64 GW of turbines in sizes below 150 MW and 114 GW below 200 MW. This means that 30% of the gas turbine capacity additions between 2007 and 2020 could be in unit sizes below 150 MW and 54% in sizes below 200 MW.

The largest below-150 MW or below 200-MW potentials are found by far in pure power generation (e.g., 35 GW below a 150-MW size) followed by distributed generation (15 GW below a 150-MW size). We also find that 33.5% of that below-150 MW potential can be found in the Southeast, followed by the West (23%), the Midwest (22%) and the Northeast (12%). We also note that this geographic distribution does not change much if we look at the below-200MW potential.

3.1 MARKET EVOLUTION

3.1.1 Overall Market Environment

The U.S. market is currently undergoing a transition from a partly competitive market towards a fully, deregulated and competitive power market, at least at the wholesale power level. Currently, a volume equivalent to more than 55% of the country's electricity consumption moves through competitive spot market and power exchange sales; however, this activity is concentrated in three NERC regions (ERCOT, NPCC, MAAC) and revolves around the activities of four independent system operators (ISOs) and power exchanges (PXs). These are the ISOs overseeing ERCOT, the New York pool, the New England pool, and the PJM pool. The California PX was shut down in early 2001 as the result of the California power crisis.

Elsewhere, moves towards competitive wholesale power markets at the regional level are still taking shape. At some point, up to 20 ISOs, regional transmission organizations (RTOs) or independent system administrators (ISAs) have been proposed across all NERC regions.

This transition is experiencing several growth problems, obviously in California where the system will have to be completely overhauled. At this juncture, several remedies have been identified and their implementation has begun. Nonetheless, this remediation process could take 3-5 years.

In contrast, the PJM PX works well and the Northeast/NY pools are expected to quickly migrate their operations to the PJM model as well. Experts also believe that the ERCOT system will work satisfactorily. There are, however, more uncertainties about the Midwest ISO. Finally, it is unclear when there will be a Southeast ISO.

During the baseline period, we expect that the U.S. market will continue to move towards a fully, deregulated competitive wholesale power market. The reason is that the process of deregulation has been badly impacted by the aftermath of the California power crisis. As a result, several states have slowed down their efforts to move toward deregulation.

In addition, the type of price volatility that has been observed (with prices often exceeding the $100/MWh level) has caused regulators to wonder about the true benefits of deregulation. In the case of California, estimates of the impacts of wholesale price increases over the last two years have ranged between $30 and $45 billion. In many other states (e.g., Maine, Montana, Oregon, Rhode Island, and Washington), higher wholesale prices have meant higher retail rates as well, sometimes resulting in temporary rate increases of 25-40%.

Such price volatility cannot be attributed to deregulation designs alone. It is also a consequence of the low level of capacity additions that occurred in the U.S. in the later part of the second half of the 1990s – as only 20 GW came on line during the 1997-1999 period.

However, the industry -- particularly independent power producers and merchant power companies – have responded in a big way since there were over 295 GW of capacity being proposed as of December 2001 and that a record 91 GW of project capacity was claimed to be under construction by the end of 2001. Altogether, over 180 merchant projects were announced in 2001 with a combined potential capacity in excess of 105 GW. It is also interesting to note that year 2001 saw more announcements of coal-fired merchant plants (for a total capacity of 45 GW, or 15% of the total merchant plant backlog). This amount even includes for the first time an ambitious project to develop by the end of the decade some 8,000 MW of mine-mouth coal plants to be located in South Dakota and Wyoming; these plants would ship their power output through new transmission links reaching into the Midwest and California.

All this activity has resulted in the fastest pace of plant start-ups since the late 1970s. Some 27 GW was added in year 2000 and it is estimated that another 46 GW should have come on line in 2001. Estimates for 2002 tend to exceed the 50 GW level –a still reasonable number since the industry is currently claiming that over 75 GW could come on line in 2002. Although some project delays have started to incur with increasing frequency, we still expect that over 115-125 GW could be added to the grid in the 2000-2002 period. However, additions will likely start slowing down in 2003 and decrease to below 10-15 GW in 2004-2005 to increase again later in 2006-2007.

For many observers, this level of activity now implies that the industry will go through a cycle of lower wholesale prices through 2002-2004. Already, some of the contracts signed in California to abort the crisis are being questioned. Future prices have decreased by more than 25%-30% in the last six months for Summer 2002 prices in ECAR, ERCOT, NEPOOL and PJM.

We believe that this period of lower prices will give time for wholesale power markets to better evolve. However, the U.S. market will still not be a fully competitive market on a national basis by 2006. By then, it will still consist of an assemblage of various regional markets operating under the jurisdiction of the various ISOs, PXs, RTOs.

Regional markets will continue to exist because of:

- Transmission constraints, which will limit the ability to move power easily between all regions
- Differences in supply/demand balances (some markets experience more power capacity shortages than others)
- Specific generating capacity fuel mixes, thus creating potential discrepancies in wholesale prices across the regions (some regions having a better gas availability)
- Retail sector restructuring timetables, which will slow the development of an integrated national market, because not all regions are proceeding at the same pace
- Variations in ISO and PX ownership characteristics, governance rules, and price-setting protocols.

Even though the next 2-3 years could be disruptive and some ISOs/PXs may be overhauled, reliably liquid competitive wholesale markets should be in place by 2004 in five NERC regions: ECAR, ERCOT, MAAC, MAIN, and NPCC. By 2005, three other regions (MAPP, SERC, and SPP) and may be WSSC should be moving towards fully competitive markets, still trailing the other regions, however.

We further expect that, by the start of the baseline period, the U.S. market will begin to function with only 5-6 regions as the result of consolidations and mergers among the various ISO, TRANSCOs and ISAs. An important factor will be the role played by the U.S. Federal Energy Regulatory Commission (FERC) which is eager to spur the development of viable Regional Transmission Operators (RTOs) while starting to consider very seriously new ways to measure market power for all wholesale power sector participants.

Exhibit 3.2 is a summary of market evolution trends for the U.S. as a whole and the five regional blocks (Northeast, Midwest, Southwest, Southeast and West) that we anticipate will evolve. These trends include wholesale power market status, level of market liquidity, competition structure, environmental regulations, gas availability, energy prices and other external factors.

In characterizing the likely U.S. power market evolution over the 2007-2020 period, we focused on four main issues:

- The extent of deregulation
- Potential environmental regulations and their potential impacts on the competition between coal- and gas-fired capacity

- Other external factors affecting power generation, focusing on potential issues involving nuclear power
- The outlook for energy prices, focusing on natural gas and wholesale electricity.

3.1.2 Extent of Deregulation

By the start of the NGT competitive phase (in the 2007-2010 time frame), competitive markets should be in place in five NERC regions and nearly in place in the remaining three (MAPP, SERC, SPP and WSSC). The U.S. market should become a fully integrated, competitive market as it approaches 2008-2009 (although it may still be subject to transmission constraints in several regions).

Even though the U.S. market will eventually become more national, in terms of deregulation, market access and power trading, much of the market's operation and planning may still continue to be done at the regional level through most of the decade, in part because of differing regional growth rates and capacity resource issues.

We expect that the separation of the market based on NERC regions will fade. Our outlook is based on the view that there will be five main regions in the market, resulting from a series of mergers and consolidations among the various ISOs that are now operating or proposed. These five regions, which we have defined as combinations of current regions for consistency with the baseline period outlook, are:

- Northeast/Mid-Atlantic (NPCC, MAAC)
- Midwest (ECAR, MAIN, MAPP)
- Southeast (SERC w/FRCC, SPP)
- Southwest (ERCOT)
- West (WSCC).

Overall, we project that by 2010, the U.S. market will exhibit a high level of liquidity probably close to 100% of the nation's total power volume moving through spot market and power exchange sales. Power bidding by generators will most likely consist of both day-ahead and hour-ahead transactions managed by the various regional ISOs and PXs. The ISOs will also set prices and manage the necessary requirements for ancillary services, real-time imbalances and congestion. However, even by 2010, there may still be differences on how these services are defined and priced.

The future U.S. competitive market will favor flexible and cost-effective technologies, such as that envisioned by SWPC's NGT. Such technologies will be needed to support:

- multiple types of sales transactions
- fast build requirements to support changing market conditions (in terms of both power demand and pricing)
- ancillary services required by the various power pools
- economic viability of generators in an environment of competitive wholesale power prices (likely to decline or remain relatively flat on a long-term basis)

- different types of power needs, ranging from peaking to intermediate and baseload power.

As the U.S. market continues to deregulate, we anticipate that competition in the power market will focus on a decreasing number of power generators. Today's power generation environment involves a wide mix of:

- Merchant power producers (MPPs) who are assembling large power generation asset portfolios, generally through a combination of both greenfield commodity projects (generally combined cycle plants in sizes above 400-500 MW) and the takeover of utility divestitures. Many MPPs have broadened their footprint and are now supra-regional and national in scope. As a result, most top merchants are targeting portfolios of 25-40 GW or more.
- Regional incumbent utilities that have not had to divest so far because deregulation has not yet hit home. They may have generation asset portfolios, which may vary between 2-3 GW and 8-10 GW. They control several plants in various areas but they all serve the same power pool. Furthermore, many of the generation sites may have site, environmental or transmission constraints.
- Municipalities and coops who need to meet growing loads while deciding whether they should stay in the power business or not. With the exception of a few large members, most of these have generation asset bases between 1 and 3 GW. In addition, their production assets tend to be concentrated on 1-2 sites (but these sites often have room).
- Industrial power plant owners that need to expand their on-site production capacity or niche IPP companies who operate or seek to develop industrial power projects. In either case, the plant owner may look for a way to oversize or revamp the existing unit, in which case part of the output could be sold as excess merchant power. Often, however, industrial sites are constrained and subject to emission control limits.

The bulk of the demand in the next 20 years will stem from the first two groups. After discussing the composition of each group, we assess the future impact of the emergence of new merchant supergiants, prompted by both gas/power convergence and industry consolidation.

<u>Merchant Power Producers</u>. The buying power of MPPs has increased exponentially in the past two years. We estimate for example that the top 20 merchant power players account for over 75% of the merchant power capacity under development. Current top players includeAEP, AES, Allegheny Energy, Calpine, Constellation, Dominion Energy, Duke Energy, Dynegy, Edison Mission, El Paso, Entergy, Exelon (combination of PECO and Commonwealth Edison), LG&E, Mirant, NRG Energy, PG&E National, PPL, PSE&G, Reliant Energy, Sempra Energy, TXU Energy, UtiliCorp/Aquila, and Williams.

The top 20 merchant power companies currently control 65% of the action with more than 310 GW of capacity either in operation or under way; they also control close to 77% of the wholesale power trading volume. The leader, Calpine, is close to a 10% market share, followed by Mirant, Reliant, NRG and Duke. The top 5 claim about 29% of the capacity pipeline. Overall, some 15 players have equity portfolios of more than 10 GW each.

Even though several players have started to lower their development targets, we find that 15 out of the top 20 players have by now succeeded in diversifying their holdings geographically by assembling supraregional or truly national footprints. This way, these players can hope to capture market upsides in regions that experience 2-3 year imbalances while they hedge against market downsides in other regions that experience changes or delays in power exchange regulations. At this juncture, 12 of the top 20 are well established in 3 or more power pool markets.

In addition, many players (e.g., Dynegy, Southern Energy, PG&E Generating, Duke, Reliant, PECO, and El Paso) trade not only the power of their merchant plants but also engage in third-party power trading to take full advantage of various location, time and form-value arbitrage opportunities. Through "gentrading" (i.e., trading around their generation), the top 20 players already trade around 300 GW of capacity and capture revenues approaching the $65 billion annual mark.

Finally, most leading electric market players also trade gas. The convergence of power and gas markets is very strong since five of the top ten power marketers – i.e., Duke, Southern, Aquila, Reliant and Dynegy - are also among the top ten gas marketers.

<u>Regional Incumbents</u>. The group of regional incumbents includes two subgroups:

- The regulated subsidiaries of larger utility holding companies which have chosen to isolate their regulated assets in their franchise areas while they expand their merchant power activities elsewhere. These regulated power generators benefit from the savvy of their parent but their decision-making process is very much influenced by the view of their regulators. Often, because they are big, they carry a lot of leverage, as long as they are not forced to divest by their regulators.
- Smaller integrated utilities which decide to stay involved in power production because they feel that they have a strong enough regional niche position.

The first subgroup includes the regulated generation subsidiaries of large companies such as Allegheny, Cinergy, First Energy, Florida Power & Light, Xcel, and South Carolina Power & Light. Together, these control over 80 GW of operating capacity.

In due time, these companies may, voluntarily or involuntarily, spin-off all or parts of the assets of their regulated power generation subsidiaries to consolidate them with the assets controlled by their unregulated affiliates. This happened with a company like Public Service Electric & Gas. However, similar efforts by Allegheny and Constellation were slowed down; their assets were deregulated but not transferred to a separate entity. That is because several utilities may not be too eager to completely spin-off their generation assets at the eve of a low-price cycle. While spin-offs are still possible with Cinergy and First Energy, other regulated entities may continue to operate for another 3-5 years, especially in Texas or the Southeast, where regulators are not pushing for asset divestitures.

There are also incumbents that do not intend to (or have decided that they could not) become strong MPPs. Instead, they prefer to assume as strong a regulated generation position as possible in their regional markets, as long as they can fend off the onslaught of merchant companies and can satisfy their local regulators. These incumbents will generally be found in states where regulators have not yet forced the divestiture of regulated assets.

However, regulated generation subsidiaries cannot be expected to make many capacity expansion investments, because their parent companies would rather make these investments through unregulated affiliates that can reap higher returns (not capped by regulation). Regulated generation companies do not have the incentive to pursue plant improvements if all the ensuing benefits accrue to the ratepayers. Some regulated utilities have negotiated a 50/50 sharing agreement but capturing only half of the benefits generally yields too low returns. As a result, most capacity expansion investments are now channeled through unregulated power merchant affiliates (the MPP group).

Furthermore, regulated generation companies want to keep their peaking power capacity as sharp as possible to avoid having to pay high prices. They are more risk averse than their unregulated affiliates who have a lot more leeway to develop their trading and marketing activities. The last thing regulated suppliers want is to have to pay high prices when, as part of the deregulation process, they committed to frozen retail revenues for periods that generally last 3-5 years.

The second subgroup includes about 20 small to medium-sized utilities such as Alliant Energy, Avista Energy, Black Hills, Carolina Power & Light, Central Vermont Public Service, Cleco, Conectiv, DTE, Energy East, DPL, Idaho Power, Kansas City, Madison Gas & Electric, Minnesota Power, Otter Tail, OGE Energy, Public Service New Mexico, Puget Sound Energy, RGS Energy Group, TECO Energy, UniSource, Wisconsin Energy, and WPS Resources.

Together, this second group controls about 60 GW of capacity. To satisfy future demand, this group will probably be starting up about 6-8 GW of combustion turbines over the baseline period.

Even though many regional incumbents may be profitable for a while, many of them will alsobe bought out. Examples of companies that recently experienced that fate include Cilco, Illinova, Ipalco, MidAmerican Energy, Nevada Power, Portland General Electric, St Joseph Light & Power, and WICOR. Others have divested their assets such as DQE, Montana Power, and Unitil. Thus, we project that, during the baseline period, the size of this second subgroup is likely to decrease form a current level of 20 or so to less than 7-8 within the next 4-5 years.

Future Industry Evolution. We are witnessing the emergence of super integrated and convergent energy merchants (ICEMers). ICEMers are driven by a strong integrated energy trading, logistics and risk management (ETLRM) unit that is in charge of gas transportation optimization contracting for power transmission capacity, gas storage position management, and capacity swaps.

ICEMers seek to systematically monetize potential arbitrage opportunities at both the wholesale and retail levels:

- at the wholesale level, they assemble asset portfolios of both gas and power assets, some owned and some contractually-controlled; the portfolio's composition is driven by the ETLRM unit
- at the retail level, they aggregate power and gas loads to maximize price and quantity flexibility and capture margin while honoring customer commitments.

The ICEM model can, however, be implemented in various ways, varying the ratio of owned-to-contracted assets, altering the mix of assets, changing the type of trading involved, and shaping the risk profile sought. So far, several companies have been seeking to form a supraregional merchant platform consisting of a 50/50 mix of commodity and logistical generation assets backed up by a ETLRM unit that is strong in at least 2-3 neighboring pools.

Rolling out an ICEM model can, however, take three years of dedicated effort, hefty doses of intellectual capital, and serious investments (of several hundreds of millions of dollars) in IT and risk management systems. Even if they have the right model, ICEMers need, more than ever, agility and strong risk management to fend off other ICEMers.

The top 11 ICEMers (i.e., Constellation, Dominion, Duke, Dynegy, Entergy, El Paso, Mirant, Edison Mission, the PG&E National Energy Group, PSE&G and Reliant) now control 63% of the U.S. unregulated upstream energy (gas/power) market activity. However, these top ICEMers know that it can take time to reach the right portfolio with sufficient size, proper energy source balance and the adequate level of geographic diversification. So far, there have been a few attempts at rationalizing or reshaping existing portfolios; however, we expect an increase in asset swaps, portfolio churning and secondary asset exchanges in 2002-2003.

The reason is that ICEMers are now more eager than ever to reap the benefits of their investments in assets, systems, and talent – *even if they decide to slow down their development plans to avoid overbuilding.* The battle between ICEMers will thus intensify especially in a wholesale market with declining prices between 2002 and 2004.

To survive, ICEMers will need to become super-ICEMers by engaging in a relentless process of continuous asset value enhancement, based on three challenges:

- The systematic use of sophisticated asset valuation techniques based on real options theory;
- Aggressive value chain position management ; and.
- Integrated mark-to-market asset portfolio management across subsidiaries.

Super-ICEMers are intent on using sophisticated simulation and real options analyses to properly codify in real-time their actionable insights on how markets shift, regulators change and competitors adjust their behavior. Such options analyses can help capture the true dynamic value of generation assets based on their ability to create arbitrages, capitalize on price volatility and respond to market signals. Unfortunately, options analysis is hard in power because electricity prices are difficult to forecast correctly, even with probabilistic models. In large part, this is because there are strong correlations between price levels and volatility levels as well as changing daily, weekly or seasonal demand and production outage patterns.

Nonetheless, well-applied options analysis can unearth true gems, and if not, will generally re-prioritize the strategic merit order of an ICEMer's assets. For example, real options analysis will reveal the true value of logistical generation assets such as pumped storage capacity, topping contracts on decentralized generation units, and output rights to load-following plants. Because they are characterized by flexible production volumes, fast start-up and surge capability, logistical generation assets are an essential ingredient in any super-ICEMer's portfolio.

Real option analysis can also be applied to design a weather-driven O&M; to identify coal generation hedges; to refine environmental compliance strategies; and to assess whether to invest in renewables.

Second, super-ICEMers will seek to continually enhance their value chain position. Although this is clearly not a case where one size fits all, an expanded value chain position generally multiplies the number of arbitrage sources and the possibility for what we call enhanced plays. For example, the value of logistical generation can be enhanced with fuel storage and form-value trading. Combined, these three activites now account for an estimated 45% of the US power industry's trading margin. Another example of enhanced play is the ability to offer comprehensive risk-managed energy sourcing to a gas/power combination distribution company.

To capture enhanced plays, super-ICEMers must coordinate the workings of 2-3 subsidiaries to offer a flawless combination of merchant power capacity development, trading and logistics, transmission and distribution, and marketing. So value chain position management is hard. It requires a flat organization and the development of business processes to achieve strong internal marketing coordination and flawless subsidiary interfaces. However, enhanced plays can bring in substantial amounts of money since they often result in long-term contracts with annual incremental revenues of $20-30 million for periods of 3, 5 or 10 years. In fact, we estimate the potential for enhanced plays in North America to exceed $150 billion in revenues by 2007.

Third, super-ICEMers need to optimize their asset portfolio on an integrated basis and according to corporate risk management guidelines. The idea is that an integrated, managed portfolio can grow faster and yield higher risk-managed margins than the same assets held by independent subsidiaries. Through portfolio integration and optimization, portfolio values could be increased by 15-35%, while future risks could be reduced.

By 2005, super-ICEMers (12-15 or so) will own over 300 GW and possibly 600 GW by 2010. By the end of the decade, they will capture at least $25 billion of wholesale-based gas/power EBITs.

3.1.3 Environmental Regulations

A potentially much more dramatic swing in the opportunities for the NGT concept could come from potential closure of coal-fired capacity. The United States currently has more than 300 GW of coal-fired capacity that is facing the prospect of increasing costs to comply with potentially more stringent regulations.

These regulations include those for nitrogen and sulfur oxides (NOx, SO2), mercury and carbon dioxide (CO2). As it stands, new coal plants must meet:

- New Source Performance Standards (NSPS), which set minimum national standards for emissions of SO2, particulate matter (PM 10) and nitrogen oxides. NSPS regulations apply to all new electric utility generating units above 25 MW.
- The National Ambient Air Quality Standards (NAAQS), which establish the limits on six criteria pollutants: carbon monoxide, lead, nitrogen oxide, ozone, PM 10 and SO2
- Prevention of Significant Deterioration (PSD) reviews, which call for new plants in attainment areas (defined under NAAQS) to install the best available control technology (BACT) providing the most emission reduction, after taking into account energy, environmental and economic impacts

- Non-attainment New Source Reviews when the plants are in non-attainment areas – in which case, the plants need to install the control technology that results in the lowest achievable emission rate (LAER)
- Regional Ozone Transport programs that require new plants to obtain their necessary emission allowances from offsets to be purchased on the open market.

In addition, it is likely that new coal plants will be subject to mercury regulations, even though there is no technology yet available on a full commercial scale.

Another issue is whether existing power plants will continue to be grandfathered or subject to new source review and potentially required to retrofit best available control technology (BACT).

On the other hand, the U.S. government has provided strong indications that it wanted to allocate funds for clean coal technology research and development. In addition, tax incentives may be available for projects using advanced clean coal technologies. Furthermore, several states such as North Dakota, Illinois and Montana, have already passed legislation toeither allocate funds or provide tax incentives.

Resolution of many of these environmental issues facing coal-fired power plants should occur by the beginning or during the early stages of the NGT competitive phase (see Exhibit 3.3).

Our estimates of aggregate and gas-fired capacity requirements over the 2007-2020 period are based on the assumption that lower emissions standards will continue to be introduced; however, we also assume that these standards will be set such that a mix of new and retrofit emission control technologies and emissions trading can to be used to avoid closure of significant coal-fired capacity.

The outlook for SWPC's NGT concept would be greatly enhanced if tighter environmental regulations, especially those for CO2, become such a cost burden that large amounts of coal-fired capacity are forced to close.

3.1.4 Nuclear Power Issues

Our estimate of aggregate and gas-fired capacity requirements assumes that at least 9 GW of nuclear capacity will be retired over the NGT competitive phase. The estimate further assumes that some capacity that will be retired early (before current operating licenses expire) and that some will operate post-2020 (with extended licenses).

Should more nuclear capacity be retired, this will create additional demandfor new capacity and more opportunities for gas-fired technologies, such as the NGT concept. At the same time, however, should less nuclear capacity be retired, this will reduce NGT opportunities.

3.1.5 Outlook for Energy Prices

Given recent and current power price increases, which have shown the difficulties in moving from regulated to competitive power markets, and the potential price volatility that may persist in the future, it is difficult to judge the future direction of wholesale power prices.

While future power prices will be an important determinant to the viability of new generating plants, such as the NGT concept, equally important will be future natural gas prices. Currently, there is a great deal of uncertainty over future natural gas prices, based on uncertainty of supply and demand.

After significant price increases between March 2000 and January 2001 (when gas prices reached the $10/mmBtu mark), prices have come down equally substantially down to the $2/mmBtu where they were in late 1999. We have assumed that prices would progressively go back to the $3-3.5/mmBtu range between 2004 and 2006 and then increase slightly during 2007-2020 (although a couple of high-price spikes such as the one observed around 2000 are also likely during the 14-year period). The resulting prevailing price range during the NGT competitive period is thus assumed to be $3.4-$4/MMBtu.

Natural gas price uncertainty will place a premium on highly efficient gas-fired generating technologies. More efficient power plants will be better able to offset potential price swings that could dramatically influence plant operating costs. For example, a $0.5/MMBtu increase in gas prices would increase the operating costs of a 250 MW plant by over $6 million/year. At the same time, a one-percentage point improvement in efficiency could reduce operating costs $10 million over a 15-year period.

During the NGT competitive phase, we expect that across the U.S. market, average wholesale electricity prices should be in the $24-46/MWh range (in constant dollars). The range in prices will in part reflect periodic price increases and decreases, but will mostly reflect differences across the future five regions in terms of generating mix and fuels likely to set the marginal generation price.

Traditionally lower electricity prices in the Midwest regions, areas with a wider reliance on coal-fired capacity, may actually increase faster if coal plant retrofit requirements multiply. In that sense, a general regional increase of $5-7/MWh is not impossible. This would close some of the gap with the historically higher prices in the Northeast region, which have tended to reflect the marginal costs of older gas/oil units.

3.2 BASELINE PERIOD PROJECTION

Historically, the need for capacity additions has been driven by electric power demand growth and by the need to replace retired capacity. While these two factors will contribute to capacity additions during the baseline period, the development of competitive markets has created opportunities for unregulated, power generating companies (GENCOs) to build power plants with intent of displacing existing capacity in terms of economic merit dispatch.

A detailed assessment of the extent of economic capacity displacement was beyond the scope of this project; however, we tried to gauge the level of implied capacity displacement by comparing our projections of total capacity additions to the levels required to meet demand growth, cover planned retirements and maintain reasonable reserve margins.

For many years, electric power demand growth tracked fairly closely with overall economic growth. However, in recent years, demand growth has been less than economic growth because of more efficient generating technologies and greater use of energy-efficient end-use technologies. Demand growth nationally was in 1999-2000 over 2.5%/year, but, with the ongoing recession, we now expect over the baseline period an average compounded growth rate at just around 2%/year.

As shown in Exhibit 3.4 and Appendix B, demand growth is expected to be highest in the WSSC (2.3%), SERC (2.1%) and ERCOT (2.1%) and lowest in the MAPP and MAIN regions (where rates may be more around 1.5%-1.7%/year).

Currently, almost 290 GW of independent power capacity has been announced for operation in 2001 or later – including 65 GW in the WSSC region; 48 GW in ECAR and 47 GW in SERC. The vast majority of this, some 245 GW, is gas-fired, turbine based merchant capacity (see Exhibit 3.5).

Over the baseline period, we estimate total capacity additions of about 139-175 GW. Our projection thus speculates that, over the baseline period, capacity equivalent to about 55-60% of the announced backlog will be brought on line. More specifically, we project that the vast majority of the total additions, or about 133-167 GW, will be gas-fired, turbine-based capacity. We project less than 2 GW of new coal-fired capacity to come on line during 2001-2006.

This level of capacity additions assumes about 10-19 GW of retirements through 2006, as well as 3-6 GW of economic displacement of existing capacity. Most of the displacement activity is focused in the NPCC, SERC, ECAR and ERCOT regions.

We further anticipate that about 67%-73% of the CC/SC capacity additions will be for CC units. Although CC configurations are currently preferred for merchant power plants, about 35-40 GW of CT units will likely be added through 2006 to meet expected peaking capacity increases, especially in ECAR/MAIN (8-12 GW), SERC (10-14 GW), MAPP (3-3.5 GW) and ECAR.

The wide range in potential additions over the baseline period relates to uncertainty on several fronts:

- Will load growth moderate or remain strong? We expect demand growth to moderate; however, continued high demand growth in some regions (e.g., those with a high concentration of "e businesses") would create more demand for capacity past 2003. For that reason, we have shown a nationwide annual rate of demand growth ranging between 1.7% and 2.2%.

- How much merchant capacity will be developed, particularly capacity aimed at competitive economic displacement? Our view is that a substantial share of the announced merchant capacity past 2002-2003 will not ultimately be developed. For example, we tallied during 2001 over 40 GW of project delays and the rate of project cancellations has accelerated in the last month of 2001. Many observers project a decline in plant announcements for 1-3 years once some regional markets experience a surplus of capacity.

- Will gas prices stay on their decreasing trajectory, after the price spike period of 2000-2001? Current projections indicate low gas prices for the 2002-2003 period followed by progressively rising prices thereafter. However other high-low price cycles are likely to appear.

- What will be the future impact of demand management programs run by utilities or power exchanges? Will these efforts be slowed down if wholesale prices decrease? Nonetheless, ISOs and PXs may be expected to incorporate in their market rules demand bids around 2003-2005 (the impact could be a reduction of 10-20 GW in national demand).

Finally, the outlook for total and gas-fired, turbine-based additions will be affected by the extent of nuclear and coal-fired retirements. The huge backlog of announced gas-fired projects could reflect an over estimation of the extent of actual retirements – particularly for nuclear plants that are now more attractive to a few independent power companies.

3.3 COMPETITIVE PHASE OUTLOOK (2007-2020)

Long-term U.S. power demand growth is expected to be in the 1.3-1.7%/year range. We anticipate that three regions will have growth rates close to the U.S. average (the West, Southeast and Southwest), while two regions should see lower growth (Northeast/Mid-Atlantic, Midwest).

Based on projected power demand growth rates, taking into account potential capacity retirements and displacements during the NGT competitive phase, new capacity requirements could vary from about 260 GW to 378 GW over the 2007-2020 period.

During that period, we project requirements for CC/SC capacity additions to range from 215 GW to 322 GW. We also forecast that, among gas-fired based capacity additions, the fraction of new CC unit capacity would drop form the high 60%s likely to occur in the baseline period to the high 50s (55-58%).

The balance includes some 30 GW of coal-fired capacity additions, 10 GW to come on line between 2007 and 2015 and 20 GW between 2016 and 2020. Most of the coal capacity will develop in the West region (18.5 GW) and the Southeast region (11.5 GW). Even though the Southeast region is characterized by high delivered coal prices, new coal plants should be economically attractive in the Entergy and TVA areas. However, the largest potential will be found in the West as long as new transmission lines can be built.

The range in potential capacity requirements over the competitive phase reflects uncertainty about demand growth. Changes in demand growth from the expected long-term rates could alter requirements by at least 50-100 GW. For example, an increase of about 0.5%/year (e.g., 2% vs. 1.5%) in the average U.S. demand growth rate would create the need for another 100 GW of capacity nationwide over the 2007-2020 period.

In our analysis, capacity retirements and displacements range between 86 GW and 160 GW. This includes 27 GW of likely retirements (at least 9 GW of nuclear capacity, 4 GW of coal plants, 5 GW of older fossil-fired steam capacity and 9 GW of older turbines). However, another 60-133 GW of additional capacity could be in play during the competitive period, depending on the heat rate improvements of the new gas- or coal-based power plant cycles available in the mid-2010s. In that context, there are uncertainties about three key factors:

- Nuclear plant retirements – The extent to which nuclear plants are retired or life extended could produce as much as a 20-25 GW change in capacity requirements – that is 10-15 GW above the 10 GW that has been assumed as a base level.

- Coal plant retirements – The degree to which environmental compliance costs affect the economic operation of existing coal-fired plants could easily contribute to a 40-100 GW swing in long-term capacity requirements.

- Economic displacement of existing plants – In addition to economic displacement that is likely to occur over the baseline period, another 40-60 GW of older oil and gas-fired plants could be displaced during the competitive phase.

Across the five regions, future capacity requirements are projected to be mostly heavily concentrated in three regions: Southeast, West and Midwest. These three regions are projected to account for about 80% of aggregate as well as CC/SC capacity requirements over the NGT competitive phase. Exhibit 3.6 and Appendix C provide more details on our projections.

In terms of the future mix of simple- versus combined-cycle additions, those regions with the highest residential peak demand will generally have the greatest need for simple-cycle peaking capacity. Going forward, however, most regions will more balanced requirements and their needs will call for a balanced mix of peaking and intermediate/baseload capacity over the competitive phase.

3.4 MARKET POTENTIAL BY MAJOR APPLICATION

In this section, we forecast the future market potential by major application, including pure power generation, industrial cogeneration, combined heat and power, repowering, IGCC and distributed generation.

Together, these six applications represent a total potential of 223-335 GW of gas-turbine-based capacity additions over the 2007-2020 period. The vast majority (215-322 GW) is projected to be gas-fired while we forecast another 8-13 GW of IGCC capacity additions.

Out of that total, between 31-55% (67-118 GW) could be addressed by turbines in sizes below the 150-200 MW range. This includes 39-79 GW in pure power applications; 4-10 GW in industrial cogeneration; 6 GW in CHP plants; 2-8 GW in repowering; and 15 GW of distributed generation.

In our mid-case projection, this translates into an estimated level of 212 GW of gas turbine capacity, based on an overall BIP mix of 33% baseload, 35% intermediate and 32% peaking. This overall BIP mix masks, however, some noticeable differences in regional BIP mixes:

- The Southeast shows the highest relative baseload need (38%) while the lowest needs are found in the Northeast and the Midwest
- The Northeast shows the highest intermediate needs (52%)
- The Midwest and West regions show the highest peaking needs (37%).

Next, we estimated the fraction of gas turbine additions that would fall under two size thresholds: 150 MW and 200 MW. In our mid-case, we find the potential for 64 GW of turbines in sizes below 150 MW and 114 GW in sizes below 200 MW. This means that 30% of the gas turbine capacity additions between 2007 and 2020 could be in unit sizes below 150 MW and 54% in sizes below 200 MW.

The largest below-150 MW or below 200-MW potentials are found by far in pure power generation (e.g., 39 GW below a 150-MW size) followed by distributed generation (15 GW below a 150-MW size).

We discuss below our findings for each type of application.

3.4.1 Pure Power Generation

We have estimated a total pure power generation CC/SC potential between 157 and 216 GW. This represents between 70% and 64% of all projected CC/SC capacity additions. The high growth capacity scenario shows a lower share of pure power generation due to a larger assumed development of industrial cogeneration and distributed generation.

The largest share (41%) of the CC/SC pure power generation addition potential is found in the Southeast, followed by the West region (27%) and the Midwest (17%).

Overall, we forecasted a US pure power generation mix that is slanted toward peaking (41%) and intermediate (37%).

We also find that between 24% and 49% of that potential is likely to involve GTs in sizes below 150 MW and 200 MW, respectively.

3.4.2 Industrial Cogeneration

We have estimated a total gas-fired industrial cogeneration potential between 20 and 36 GW – with the largest share (41%) to be found in the Southeast, followed by the Midwest and the West regions (each with a potential 20% share). Most of that capacity (67%) will meet baseload needs, most of the balance (32%) serving intermediate needs.

Overall, we forecasted a US industrial cogeneration mix that is heavily slanted toward baseload (67%) and intermediate (32%).

The average industrial cogeneration GT size is projected at 199 MW, that is only 12% below the average for the pure power generation segment – even through the average cogeneration project size may be 55% lower than the average power generation project. This can be explained by three observations:

- More cogeneration applications will involve 1x1 configurations
- A large number of cogeneration applications will be a 1x1 single train
- The fraction of oversized cogeneration projects will increase as the pure power generation market becomes more fluid.

As a result, we find that between 37% and 64% of that potential is likely to involve GTs in sizes below 150 MW and 200 MW, respectively.

3.4.3 Combined Heat and Power

Our estimate of potential CHP capacity additions in the US between 2007 and 2020 ranges from 6 to 10 GW. This potential is almost evenly divided between four regions; the Northeast, the Midwest, the Southeast and the West.

CHP applications will mostly serve intermediate needs (52%) followed by peaking needs (26%) and base needs (23%). In our estimate, most applications will involve GTs below 150 MW.

3.4.4 Repowering

We forecasted a potential development between 20 GW and 35 GW – that is roughly 9-10% of the total projected CC/SC capacity additions. This potential is found to be the strongest in the Midwest (29%), followed by the Northeast (23%) and the West and Southeast (each around 18%).

We also find that repowering could have a BIP mix similar to that of industrial cogeneration, with an emphasis (63%) on meeting baseload needs and the balance (37%) associated with intermediate needs.

We project an average gas turbine size of 248 MW. In our estimation, only 5% of repowering applications would involve GT units below 150 MW and 42 % below 200 MW.

3.4.5 IGCC

We forecast that IGCCs could capture about half of the 20 GW of new coal-fired capacity that we have projected to come on line between 2015 and 2020. This amounts to a projected capacity range of 8-13 GW over that 5-year time frame.

This forecast is predicated on several assumptions:

- The availability of a new IGCC technology by the early 2010s which would be capable of meeting the following characteristics: a capital cost of $1,050/net kW; a heat rate of 6,900 Btu/kWh; a fixed operation and maintenance (O&M) cost of $15/kW, a variable O&M cost of $5/MWh and a capacity factor of 88%.
- A balanced regulatory climate that would be consistent with the ability of major power producers to trade emission credits.

We base our findings on a detailed modified levelized cost analysis which shows, for example, that, in the VACAR region (a subset of the Southeast), the IGCC could compete with a new H-based combined cycle around 2012-2014. For the purpose of our this comparison, we assumed that the H-unit would have a capital cost of $484/kW net, a heat rate of 6,396 Btu/kWh, a fixed operation and maintenance (O&M) cost of $10.4/kW, and a variable O&M cost of $1/MWh and a capacity factor of 93%.

Under these assumptions, we find that the IGCC and the H-based CC have very similar levelized costs in VACAR - estimated at $32.6/MWh and $32.7/MWh, respectively, on the basis of a $3/mmBtu Henry-Hub gas price equivalent.

We also find that, as soon as the gas price is assumed to be around the Henry-Hub equivalent of $3.35/MWh, the IGCC solution can offer a levelized cost that is 7-8% lower than a H-turbine based cycle. This may be enough to warrant the beginning of some market penetration by 2015. The same happens in other parts of the Southeast and the West.

We also conclude that it is likely that these IGCCs would use turbines larger than 150 MW and we foresee only 15% of below-200 MW GT capacity additions in that segment. In fact, the technical and economic estimates that we used for our economic comparison are based on a 400MW 1x1 IGCC cycle with a 260 MW GT unit. In our estimation, the average GT size is 277 MW in the U.S. IGCC segment.

3.4.6 Distributed Generation

We forecasted, for the 2007-2020 period, a potential market of 12 GW to 25 GW in DG plants above 30 MW. This will include medium-sized gas turbine units built to provide congestion relief or help buffer wholesale price fluctuations for municipalities, coops and retailers.

These DG additions are projected to be most prevalent in the Midwest region where we forecasted a potential development between 3.6 GW and 7.5 GW followed by prospects in the 2.5-5 GW range in the Northeast, West and Southeast.

In our mid-case, which is based on total DG GT capacity additions of 15 GW, we project an average gas turbine range of 84 MW, reflecting our finding that most GT ordered in that segment are likely to be best suited by turbines in sizes below 150 MW.

3.5 RESULTS BY REGION

Most of the projected CC/SC capacity additions are to be found in the Southeast (34%), followed by the West (25%) and the Midwest (21%). The balance will consist of the Northeast (12%) and the Southwest (9%).

Sets of detailed GT potential estimates for each region can be found in Appendix F. Overall, we find that the largest GT capacity potential is found in the southeast region (combining the current SERC, FRC and SPP regions). The next two most active regions are the West (current WSSC region) and the Midwest (combination of ECAR, MAIN and MAPP).

3.5.1 Southeast

As defined, the Southeast includes regions with a relatively high demand rate, a gas-friendly environment, and a mix of displacement possibilities, mostly located in the SPP region. This is reflected in a BIP mix that is 35% intermediate, 31% peaking and 34% baseload.

Our analysis shows total CC/SC capacity additions between 88 GW and 118 GW. In our mid-case, we projected some 78 GW of capacity ordered over the 2007-2020 period in the region. The Southeast also leads in terms of its GT potential for pure power generation (41% of the nationwide pure power potential) and industrial cogeneration (39% of the nationwide potential). However, the Southeast lags behind other regions in other (but less important) applications such as CHP, Repowering and Distributed Generation.

Out of these 78 GW, about 21.5 GW (28%) could involve units below 150 MW and 40.5 GW (52%) could be associated with units below 200 MW. The fact that these shares are the lowest of all regions is offset by the fact that the overall Southeast CC/SC market is the largest.

3.5.2 West and Midwest

The next two most active regions are the West and Midwest regions, with total CC/SC capacity additions in the 61-82 GW range and 35-68 GW range, respectively. The West ranks first for IGCC applications and second for pure power generation while the Midwest ranks first for repowering and DG.

In our mid-case, we project 56 GW of GT capacity added in the West and 40 GW in the Midwest. In the later, we find that 35% of the GT capacity is likely to involve GT units below 150 MW, while units below 200 MW would capture an estimated 55% of all GT capacity added in the Midwest. In contrast, the West shows the smallest fractions of GT capacity below 150 MW (27%) and below 200 MW (51%).

Exhibit 3.1 - U.S. Market Prospects Summary (2007-2020)

CC/SC Application	Market Size (GW) Low	Market Size (GW) High	Per Duty Cycle (%) Base	Per Duty Cycle (%) Intermediate	Per Duty Cycle (%) Peaking	Gas Turbine Size Range (MW) Low	Gas Turbine Size Range (MW) High	Gas Turbine Size Range (MW) Average
Pure Power Generation	157	216	22%	37%	41%	*30*	*360*	*225*
Industrial Cogeneration	20	36	67%	32%	1%	*30*	*360*	*199*
Combined Heat and Power	6	10	23%	52%	26%	*30*	*150*	*83*
Repowering	20	35	63%	37%	0%	*100*	*360*	*248*
IGCC	8	13	95%	5%	0%	*150*	*360*	*277*
Distributed Generation	12	25	12%	36%	52%	*30*	*150*	*84*
TOTAL	**223**	**335**	**33%**	**35%**	**32%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Overall GT Capacity Share (%) <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	148	35.1	72.9	24%	49%	16%	34%
Industrial Cogeneration	18	6.8	11.6	37%	64%	3%	5%
Combined Heat and Power	6	5.9	5.9	100%	100%	3%	3%
Repowering	18	0.9	7.4	5%	42%	0%	4%
IGCC	7	0.0	1.0	0%	15%	0%	0%
Distributed Generation	15	15.4	15.4	100%	100%	7%	7%
TOTAL	**213**	**64.1**	**114.2**	**30%**	**54%**	**30%**	**54%**

	Per Duty Cycle (%)			GT Capacity (GW) below 150-200 MW		Regional Share (%) of GT Capacity <150 -200 MW	
By Region	Base	Intermediate	Peaking	<150 MW	<200 MW	<150 MW	<200 MW
Northeast	28%	52%	20%	7.6	13.2	35%	61%
Midwest	28%	35%	37%	14.1	22.0	35%	55%
Southeast	34%	35%	31%	21.5	40.5	28%	52%
Southwest	38%	36%	26%	6.1	10.1	36%	59%
West	34%	30%	37%	14.8	28.5	27%	51%
TOTAL	**33%**	**35%**	**32%**	**64.1**	**114.2**	**30%**	**54%**

Source: PA Consulting

Exhibit 3.2 -- Summary U.S. Market Evolution

U.S. Region	Northeast/ Mid-Atlantic	Midwest	Southeast	Southwest	West	U.S. TOTAL
Extent of Deregulation/Privatization						
-- Wholesale Power Market Status	In Place	In Place	Developing/ In Place	In Place	Restructuring	In development; 50% mature
-- Level of Market Liquidity	High	Medium-High	Increasing	Increasing	Challenged	Moderate-High
-- Power Bidding Mechanisms	Mature	In implementation	Immature	Maturing	Needs restructuring	Varying across regions
-- Structure of Competition	Very Balanced	Balanced	Balkanized	Balanced	Sticky	50% balanced; 50% Sticky
Environmental Regulations	Favorable to gas	Favorable to gas near-term	Favorable to gas near-term	Favorable to gas	Favorable to gas near-term	Favorable to gas
Gas Availability	Neutral	Favorable	Neutral/ Favorable	Favorable	Unfavorable/Neutral	Favorable
Energy Prices						
-- Electricity (wholesale)	\$31-43/MWh	\$24-34/MWh	\$25-39/MWh	\$26-35/MWh	\$32-46/MWh	\$24-46/MWh
-- Natural Gas (for generators)	\$3.5-4.4/ MMBtu	\$3.2-4.1/ MMBtu	\$3.2-4.2/ MMBtu	\$3.0-4/ MMBtu	\$3.6-4.4/ MMBtu	\$3.2-4.4/ MMBtu
Other External Factors	Nuclear	Nuclear/Coal	Nuclear, Coal	Regional	Nuclear, Coal	Nuclear, Coal

SOURCE: PA Consulting

Exhibit 3.3 -- Potential Environmental Issues For Coal-Fired Generators (2000-2010)

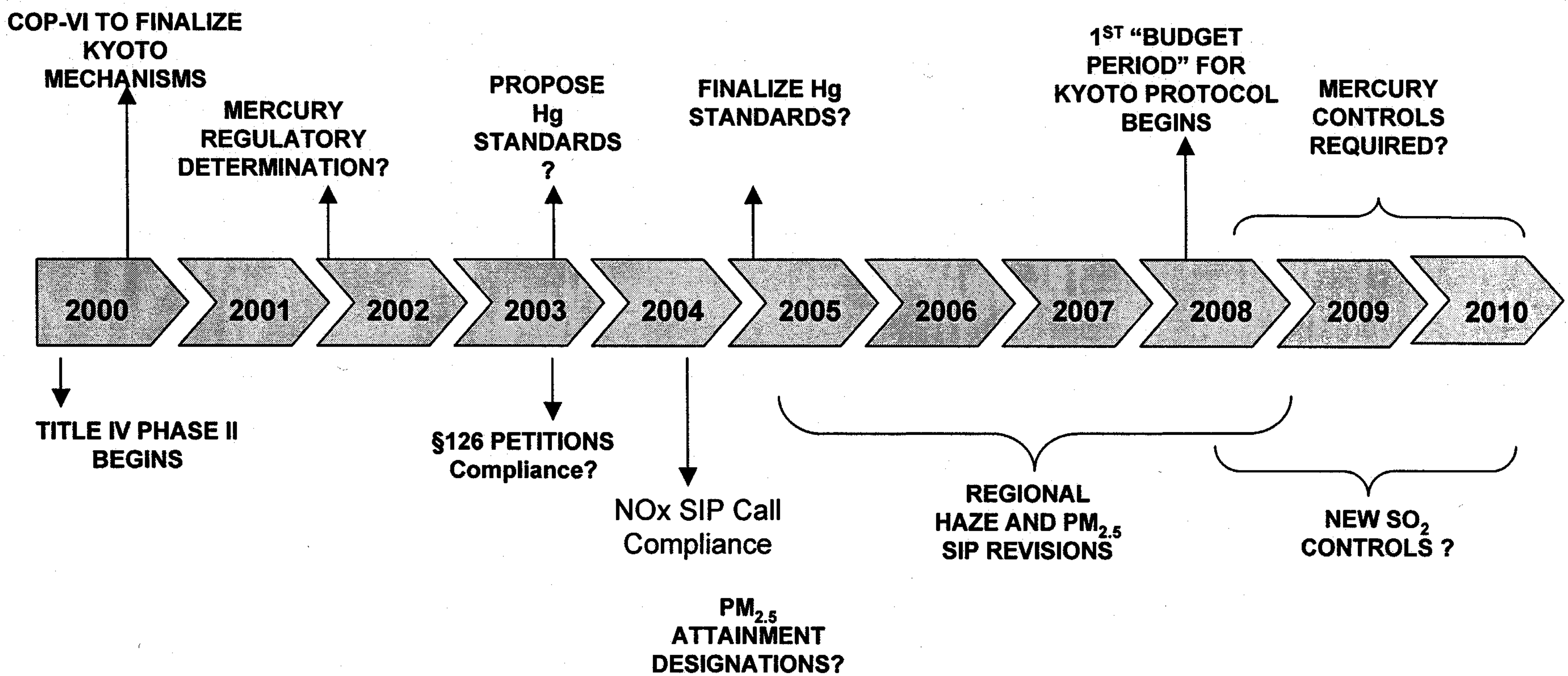
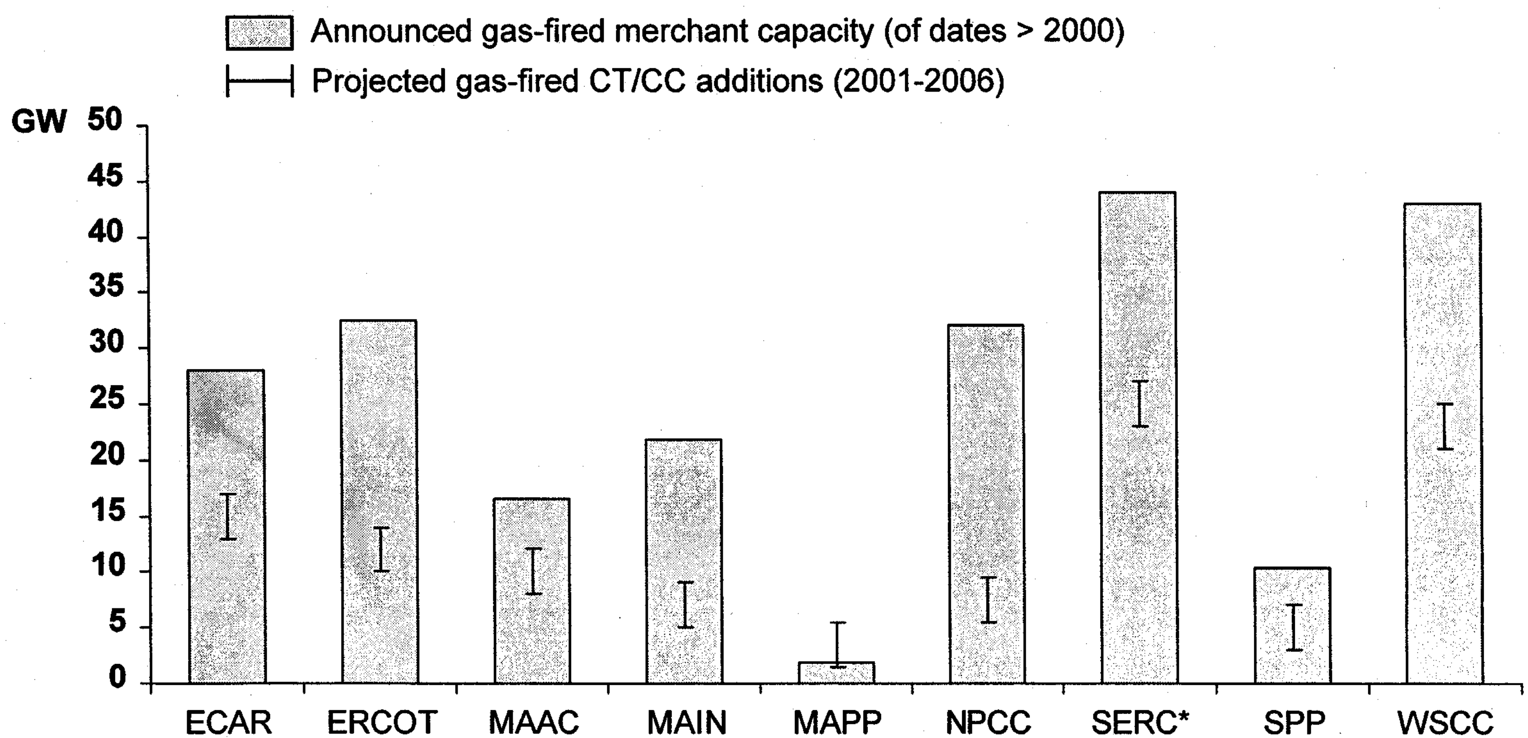


Exhibit 3.4 -- Summary U.S. Baseline Period Outlook by NERC Region (2001-2006)

	Projected Demand Growth (%/yr)	Projected Capacity Additions (GW)		Implied Capacity Displacement (GW)
		Total	Gas-Fired CT/CC	
ECAR	1.6-2.0%	15-20	14-19	2.5-4
ERCOT	1.9-2.3%	11.5-13	10.5-12	3-4
MAAC	1.6-2.1%	9-12.5	8.5-12	1-2
MAIN	1.5-1.9%	10.5-15	10-14.5	1-2
MAPP	1.4-1.75%	2.5-3.5	2.1-3.25	0.2-0.75
NPCC	1.3-1.7%	12-15	11.5-14.5	2-4
SERC	1.9-2.4%	40-49	39.5-48	3-4
SPP	1.5-2.0%	7-10	7-10	0-2
WSCC	2.1-2.6%	31.5-37	30-34	0.5-2
U.S. TOTAL	1.7-2.2%	139-175	133-167	13-25

SOURCE: PA Consulting

Exhibit 3.5 -- U.S. Gas-Fired Capacity Activity (2001-2006)



** including FRCC*

Exhibit 3.6 -- Summary U.S. Competitive Phase Outlook (2007-2020)

U.S. Region	Northeast/ Mid-Atlantic	Midwest	Southeast	Southwest	West	U.S. TOTAL
Demand Growth (%/yr)	1.3-1.7%	1.4-1.8%	1.7-2.1%	1.6-2.0%	1.7-2.3%	1.6-2.0%
Capacity Additions (GW)						
-- Total Additions	24-43	45-81	94-126	22-33	73-95	260-378
-- Gas CT/CC Additions	21-39	35-68	85-113	18-28	56-74	215-322
Capacity Displacement (GW)	20-35	25-49	15-35	10-17	16-24	86-160

SOURCE: PA Consulting

4. INTERNATIONAL KEY TARGET MARKET OUTLOOKS

In this chapter, we review the outlook for the five international key target markets (KTMs) selected for examination in this engagement:

- Brazil
- Mexico
- Germany
- Italy
- Spain.

In each case, we discuss the market potential for each type of application (pure power generation, industrial cogeneration, combined heat and power, repowering, IGCC and distributed generation) in each KTM. We also estimate the fraction of the CC/SC marketthat is associated with various types of power (i.e., baseload, intermediate and peaking) and various GT sizes.

We conclude that the non-US KTM markets (see Exhibit 4.1) could require between 149 GW and 217 GW of capacity additions over the 2007-2020 period, out of which we expect between 76 GW and 131 GW of gas-fired capacity additions. Adding between 5 and 10 GW of IGCC capacity, the total amount of gas-turbine-based CC/SC additions is projected to range between 81 GW and 141 GW.

Over the 14-year timeframe, we forecast a BIP mix that is stronger on baseload (36%) than intermediate (31%) while peaking needs could account for 33%, but this is the composite result across the five KTMs where BIP mixes are quite different:

- Mexico shows the highest relative baseload duty usage (44%) followed by Italy (38%) while Brazil has the lowest usage (26%)
- Germany and Brazil have the highest fractions (41% and 40%, respectively) of intermediate duty usage
- Italy and Brazil have the highest peaking need usage (36% and 35%, respectively).

If we now focus on a mid-case situation, we find that the anticipated mix of simple and combined cycles that these BIP mixes are likely to entail results in a forecasted need for 85 GW of gas-turbine capacity additions over the 2007-2020 period.

Next, we looked at the size distribution of these GT additions. We found that four applications (i.e., pure power, IGCC, repowering and industrial cogeneration) would require in the 2007-2020 period average GT sizes above 185 MW while the remaining two others would be characterized by average GT size of 79-121 MW. More specifically, we found that the average sizes for various applications would be:

- 202 MW for pure power generation
- 162 MW for industrial cogeneration
- 105 MW for CHP

- 228 MW for repowering
- 254 MW for IGCCs
- 78 MW for distributed generation.

We further estimate that, in our mid-case, this level of gas turbine additions should create the need for 33 GW of turbines in sizes below 150 MW and 56 GW below 200 MW. This means that 39% of the gas turbine capacity additions between 2007 and 2020 could be in unit sizes below 150 MW and 66% in sizes below 200 MW.

The largest below-150 MW or below 200-MW potentials are found by far in pure power generation (e.g., 16.5 GW below a 150-MW size) followed by industrial cogeneration and distributed generation (around 6 GW each, below a 150-MW size). The markets that a NGT up to 150-200 MW could address include 16-33 GW of pure power generation; 6.5-9 GW of industrial cogeneration; 3.1-3.5 GW of CHP; 0.7-3.8 GW of repowering; and some 6 GW of distributed generation.

We also find that Brazil and Mexico show the highest potential below 150 MW – roughly around 8.2-8.4 GW each. However, Brazil appears the most attractive on the low GT size end since 47% of the GT capacity additions could be below 150 MW. The below-150 MW potential is also quite close in the three other KTMs but it ranges between 4.9 GW in Spain and 5.7 GW in Italy.

The same finding applies to the below-200 MW potential with Brazil and Mexico each offering a potential 40-50% higher than in any other KTM.

We elaborate on our findings in the following sections. For each KTM, we:

- discuss the likely market evolution (leading to the NGT competitive phase), as shown in our Exhibit 4.2 summary
- review the baseline period outlook (see summary estimates in Exhibit 4.3)
- outline demand growth and capacity requirements during the competitive phase (Exhibit 4.4).

We also present the results of our CC/SC and GT size market segmentation analyses. Detailed back-up tables can be found in Appendix F.

4.1 BRAZIL

4.1.1 Market Evolution

Brazil began the transition to a deregulated, competitive market (See Appendix D) when it created its wholesale electricity market (named MAE) in September 2000. At that juncture, wholesale power generators negotiated nine-year power sale agreements with distributors covering the period 1998-2006. Prices that distributors can pass along through retail rates were designed to be governed by the Valor Normativo (VN) or normative values (i.e., reference prices) that were established by Brazil electric sector regulator (ANEEL) to help ease the transition from regulated to competitive power price. Initially, the VN was set at Rupees 57.20/MWh (or $32.40/MWh).

However, the recent power crisis (due to a severe drought in a hydro-dominated power system) has affected many parts of the power sector. To respond to the crisis, the government decided to implement a rationing program that specifies usage-reduction targets of 15-25% by customer category. In addition, industrial end-users with consumption over 2.5 MW were allowed to resell their output.

The crisis clearly upset the VN-based pricing system as MAE prices shot up to R$684/MWh (around $285/MWh) in May and June. Generators who could not supply power to the distributors were still selling at the low VN prices while they had to purchase power at 10-15 times higher price. Payment for the resulting bill – estimated at more than $2 billion – is under negotiation.

In the meantime, the crisis also affected the make up and operations of the MAE, which is now much more under the control of ANEEL, the Brazilian regulatory agency. MAE's board was dismissed and a new council (Comae) has been formed with representations from ANEEL, generators and distributors.

Furthermore, the crisis cast a doubt on the MAE pricing scheme. ANEEL changed the values of the VNs twice without giving much opportunity for consultation or public comment. New VN rates have increased by 45-80% depending on the type of plant's fuel and size. Now, most VNs are in the $38-44/MWh range. Still, there is very little liquidity on the MAE market.

The rationing program is likely to prevail through 2002. In addition, new capacity additions may be delayed as private sector developers reassess their risks. The government, however, moved to offer some incentives, including the set up of an exchange-rate risk management policy to protect developers from gas price fluctuations (as the value of the real currency also came under attack in 2001). In addition, the BNDES planning agency announced that it would finance a higher share (80% vs. 35% previously) of development costs for gas-fired plants included in the government's priority construction program (consisting of some 49 thermal plants that were expected to come on line before the end of 2003). Finally, ANEEL's new VN rates set higher rates for the priority gas-fired plants.

Now, It remains to be seen when the real transition to competition will take place. Originally, it was supposed to begin in 2003 when the current contract volumes were to be freed up in 25% increments each year through 2006 and generators and distributors were to be allowed to compete for new customers and suppliers.

The country has already privatized most (20) of the major electric distribution companies and has privatized several (4) of the power generating companies. The major power companies that have yet to be privatized (especially Eletrobras' subsidiaries of Chesf, EletroNorte and Furnas) should be sold during the baseline period, even though the current consensus is that no privatization is likely to take place until the next presidential election of 2002.

Extent of Deregulation. We still expect a fully open competitive market should be in place by 2007, the start of the NGT competitive phase. The market will, however, take time to become highly liquid. Initially, perhaps only 10-15% of total power volume will involve spot market sales. Wholesale and spot market transactions will increase slowly as the market moves away from the transition contracts set up under Valor Normativo or reference pricing.

The wholesale market will involve both privatized GENCOs and IPPs competing to build new power plants and power sales competition will involve generators, including some large industrials selling excess power from on-site generating plants, as well as power marketers. The specifics of power bidding have not yet been determined, but are likely to follow those set in other competitive markets (e.g., United Kingdom, United States), with day-ahead supply bidding, marginal cost dispatch and short-term marginal cost pricing. It is quickly that there will be a transitional pricing phase beginning in 2006/07 to ease the market to fully competitive pricing after the expiration of VN-based transition contracts.

Environmental Issues. Nuclear and coal issues are not likely to be a major concern in Brazil, given its historic emphasis on hydropower and its planned future reliance on hydropower and gas. Still, 2.5 GW of additional nuclear capacity is planned during the competitive phase and more could be envisioned if hydro development falters or if gas supply (from regional imports) is inadequate to sustain development of gas-fired capacity.

Outlook for Energy Prices. The competitive VN price was set at about $32/MWh in 1999 and recent IPP bids to sell power have been in the $30-40/MWh range. Average wholesale prices, largely determined by hydroelectric plants, have been about $30/MWh.

After the end of the current crisis, we expect average wholesale prices to remain in the $36-41/MWh range, on a constant dollar basis; however, there is likely to be a high level of price volatility as shown during this crisis period, given the predominance of hydroelectric capacity in Brazil. Some estimates for gas-fired/CC plants have put future marginal costs (in current dollars) at about $45/MWh by 2005 and $60/MWh by 2020.

Natural gas prices are expected to be in the $2-3/MMBtu range during the competitive phase; however, this assumes that gas prices will remain somewhat controlled (as they are now) to encourage development of gas-fired capacity and that Petrobras will remain the predominant supplier.

The long-term dynamics of the gas market could change if a more competitive market were to develop, particularly for import supplies. Currently, Petrobras is using a $2.58/MMBtu reference price in its new price-hedging system put in place as a result of the crisis. In 2000, Petrobras was charging about $2.5/MMBtu for gas from the Bolivia-to-Brazil pipeline and the government had set $2.47/MMBtu price caps for imported gas. These price caps had been instituted to try to add a measure of certainty to the market to help the near-term development of gas-fired power plants.

4.1.2 Baseline Period Projection

Estimates of electric power demand growth during the baseline period range from about 3.5%/year to about 6%/year, with the different estimates generally tied to overall expectations for Brazil's general economic growth. Our view is that power demand will grow 4-4.5%/year during the baseline period.

The official government forecast or plan in 2000 called for adding 45 GW (including 15 GW gas-fired) over the 2000-2009 period, up from the 36 GW that the 1998 plan called for. However, the government recognized that its 2000 goal was too ambitious and, accordingly, set in mid-2001 a new goal of adding about 20 GW between 2001 and 2004 – based on completing 7.8 GW of new hydro capacity; adding 6.4 GW of gas-fired capacity and rolling-out 2 GW of diverse facilities including small hydro, cogeneration, and wind. In addition, the government has launched a special program of 4 GW of mobile capacity installed on barges that could be moved around. By the end of December 2001, up to 5 GW of new hydro site concessions had been awarded in two rounds of solicitations (some won by large companies such as Tractebel, Electricite de France and Electricidade de Portugal).

At this juncture, our datebase shows a total of 32 CC gas-fired projects under development, representing a combined potential capacity of 15.4 GW. A third of the capacity is associated with projects between 400MW and 500 MW while another third is clustered in project sizes between 700 MW and 900 MW.

As a result, we expect total capacity additions of about 16-25 GW during 2001-2006, with the uncertainty mostly related to future load growth (see Appendix E) and the ability of developers to bring plants on line in the next 4 years. We project gas-fired capacity additions between 5 and 7 GW. We still see a probability of fewer gas-fired additions as the result of continuing uncertainties on future power prices and natural gas pricing and availability.

4.1.3 NGT Competitive Phase Outlook (2007-2020)

Brazil is the largest energy market in South America; however, its ability to expand its power sector and the shape of the expansion will be tied, not only to future demand growth and the successful implementation of its competitive market, but also to development of regional resources.

Our outlook for the NGT competitive phase is for demand growth of 4%/year, based on estimates ranging from 3-5%/year. Depending, however, on the extent of load growth, total capacity additions could range from 55 GW to 75 GW and gas-fired additions from 15 GW to 30 GW (see Appendix F). The range in potential capacity requirements, particularly for gas-fired units, is partly tied to Brazil's ability to continue to invest in new gas pipelines to support regional gas imports. In addition, there is uncertainty over potential increases in the amount of power imported from Argentina and Venezuela. Our forecast considers that no additional nuclear plants will be added, beyond the 2.5 GW currently planned; however, a more ambitious nuclear program would reduce the requirements for gas-fired power plants.

Perhaps the greatest uncertainty in the Brazilian outlook is the extent to which large-scale hydroelectric plants can continue to be developed, particularly in areas that may became subject to more environmental sensitivities. Nonetheless, we have assumed that Brazil will be able to continue to develop hydroelectric plants, including a significant portion of the more than 30 GW now planned for development in the Amazon basin.

4.1.4 Market Potential Assessment

We forecast over the 2007-2020 period, between 15 GW and 30 GW of CC/SC capacity additions. This includes a very strong pure power generation market of 9.2-19.75 GW, representing 69% of all projected gas-fired turbines orders. Our estimates show that the only other significant market is likely to be the industrial cogeneration market with a 19% contribution, that is the equivalent of 4 to 6 GW between 2007 and 2020.

This level of CC/SC capacity additions translates into a projected need for 17 GW of GT capacity additions over the period. We estimated that 47% of that need (8.2 GW) would involve turbines below 150 MW; and 81% (14.1 GW) would be associated with turbines below 200 MW. The two most attractive segments for smaller size turbines are pure power generation and industrial cogeneration.

Overall, we found that the average sizes for various applications would be:

- 185 MW for pure power generation
- 142 MW for industrial cogeneration
- 66 MW for CHP and 70 MW for DG
- 215 MW for repowering

<u>Pure Power Generation.</u> It is difficult to predict how the future Brazilian wholesale power market will behave since it has not started yet. It is also reasonable to expect that the new exchange's governance and guidelines go through a couple of iterations, given the highly contestable nature of the Brazilian market and the dominance of Electrobas.

Future dispatching of the Brazilian wholesale power markets will be influenced by several factors:

- The huge amount and proportion of hydropower (over 60 GW, over 90% of current installed capacity)
- Some transmission congestion issues between the East and West load regions
- The impact of a new power exchange
- The competitive behavior of a broader slate of power generators as more large IPPs become involved in the Brazilian market.

We anticipate a strong increase in price volatility in the Brazilian market between 2004 and 2008. As a result, the availability of a NGT-type technology will be quite welcome to address about a third of the intermediate and peaking pure power needs that we have forecasted over the 2007-202 period.

In our estimation, 39% of the 12 GW of GT capacity needed in that segment could involve turbines below 150 MW and another 38% would rely on GT units between 150 MW and 200 MW.

<u>Industrial Cogeneration.</u> Self-production currently accounts for only 3% of total generation, with an installed capacity estimated at below 1 GW. The overall potential for cogeneration has been estimated at 9-12 GW but a large fraction of that potential is not gas-based.

Over the 2007-2020 period, we estimate the potential for industrial gas-fired cogeneration in units above 30 MW at between 4 and 6 GW or the equivalent of 125-225 MW per year. We anticipate quite a few multi-train configurations to best take advantage of possible market optionalities. As a result, about 67% of that capacity can be served by GTs in sizes below 150 MW and 92% by GTs below 200 MW. The average GT size in that segment is estimated at 142 MW.

Combined heat and power (CHP). There will be limited opportunities in Brazil for this type of application – less than 0.75 GW overall over the 2007-2020 timeframe, based on urban commercial applications requiring cooling. Our median estimate is for 400 MW, all using turbines below 150 MW.

Repowering. Opportunities will be very limited given the very low thermal base (less than 5 GW) in place in Brazil. More sites may become eligible toward the end of the period when some of the earlier IPPs (developed in 1997-2000) will have reached their 20-year life. Our range estimate is 0.7-2 GW; furthermore, the 3-6 repowering projects will use turbines above the 150 MW size threshold.

IGCC. We also found that IGCCs would not be competitive in Brazil. Our analysis shows a levelized cost for an IGCC of roughly $42/MWh compared to a range of $27-34/MWh for a range of advanced combined cycle technologies using the H gas turbinetechnology with various degrees of possible improvement combined with gas prices equivalent to $3-3.50/mmBtu (Hub Henry) in 2010 increasing to $3.5-4/MMBtu in 2020. The main reason is that coal prices are too high (forecasted at $1.36/MMBtu in 2010 increasing to $1.55/mmBtu in 2020).

Distributed Generation. Distributed generation applications over 30 MW could find room in Brazil, given growing locational grid constraints and the expected rise of privatized distribution utilities owned by foreign investors.

At this point, private power producers can sell power to existing sites over 10 MW. The market in power-only DG applications over 30 MW could be around 50-100 MW per year, the majority being non-utility projects or projects owned by privatized utilties. These plants will all use turbines in sizes below 150 MW and in large part be peaking units in urban fringe areas and intermediate plants in more rural settings.

In our mid-case scenario, we estimated 1 GW of GT capacity additions.

4.2 MEXICO

4.2.1 Market Evolution

Of the five international KTMs, Mexico is furthest behind in terms of the development of a competitive, electricity market. Introduction of a competitive wholesale market, the Mercado Electrico Mayorista (MEM), was proposed in 1999 by then President Zedillo. However, in 2000, Zedillo lost his bid for re-election to President Fox, who was not thought to be supportive of deregulation and competition in the electric sector. However, Fox did prepare a electric sector reform bill that he intended to submit in March 2001. The need to act more urgently on a fiscal and tax reform has, however, delayed the process. For all practical purposes, the reform will have to wait for 2002.

Although Fox will in part continue the energy liberalization process started by his predecessor, his agenda is not likely to include any attempt at splitting CFE, the powerful national utility. Instead, there will be some measures easing IPP investments; for example, new hydroelectric concessions may for the first time be offered to private developers. In addition, cogenerators are now allowed to sell all their excess power (instead of being limited to 20 MW previously) and self-generators can sell 50% of the output for purposes other than on-site needs.

As a result, we do not anticipate significant movement towards a competitive market during the baseline period – there is still no sign of possible CFE asset privatization and the formation of a wholesale power market may not occur before 2007. Instead, we expect most power sector activity in 2001-2006 to involve construction of new power plants on a build-lease-transfer (BLT) basis that sell their output to still government-owned CFE.

At the same time, Mexico's power margin has been dwindling down as the result of delayed BLT investments and strong demand growth (in the 6-7% range). The reserve margin dropped to less than 9% in 2000 and reached 0% in April 2001.

Extent of Deregulation. At this point, only the state power companies can distribute and sell electricity to the general public. Independent power production is only allowed when the unit is less than 30 MW and sells all its power output to CFE; if the plant cogenerates or is a self-generation unit; or if the output is sold to CFE under a long-term agreement (generally a 25-year PPA).

However, we expect a competitive wholesale power market to develop during the NGT competitive phase, most likely around 2007-2009. Prior to a full opening, we anticipate that private generators would be allowed to sell under more flexible terms directly to the wholesale market and to certain types of eligible customers. For example, such direct sales may be able to reflect capacity costs.

The next stage of the transition to competition would include the privatization of CFE through the creation of several independent GENCOs. Ultimately, a full-fledged wholesale generation market would be launched by an ISO overseeing transactions between IPPs, privatized GENCOs, as well as some power marketers and select industrial power generators.

Initially, and probably through the first half of the NGT competitive phase, Mexico's market will not be extremely liquid, in part because there are many (like 15-20) transmission discontinuities throughout the country. We think that most sales will first involve bilateral contracts between generators and distributors and/or end-users.

Power bidding mechanisms will develop, however. A first tentative structure was already proposed in 1999. Under that scheme, generators would bid supply one day ahead, with supply priced at the Last Accepted Offer (LAO), which would be the most expensive generator dispatched with no transmission constraints. If constraints are present, there would be some form of locational pricing, with the overall system dispatched on a least cost basis.

The competitive market structure that was originally proposed also envisioned that the LAO price could be increased with a cost of failure adjustment if reserve margins were low. The Secretary of Energy would also have the ability to introduce K factor or capacity payments. Both of these last two items would increase wholesale power prices to help promote new power plant construction. These factors can also bring uncertainties if their administration is not transparent.

Environmental Issues. No environmental issues are foreseen that would limit the use of gas turbine technology. Natural gas should remain the preferred fuel for future capacity additions, in part to help air pollution in Mexico City and along the industrialized U.S./Mexican border.

Potential issues related to nuclear and coal-fired capacity should also have a minimal impact on the future power market. Currently, nuclear (about 1.5 GW) and coal-fired (less than 3 GW) capacity account for only about 10% of Mexico's generating capacity.

Retirement of this capacity for environmental reasons would only minimally boost the prospects for gas-fired capacity. Conversely, should their use expand (which we see as unlikely), the outlook for gas-fired capacity would diminish, but again only marginally.

Outlook for Energy Prices. Wholesale power prices are expected to remain in the $25-30/MWh range on a constant dollar basis, roughly equal to current price levels as indicated by recent IPP supply bids to CFE.

Mexican natural gas prices have historically been quite comparable to U.S. prices. We expect that future prices will remain fairly stable in the $2.5-3/MMBtu range.

The key natural gas issues in Mexico are the need to continue the expansion of the domestic distribution infrastructure and the necessity to continue the development of domestic gas production and/or U.S. import pipelines. Both activities are expected and factored into our outlook for gas-fired capacity additions.

4.2.2 Baseline Period Projection

Power demand has recently been increasing about 6-7%/year and the Mexican government's forecast is for growth to average up to 5.5%/year through 2007 as the result of the 2001 recession. Given the likely continuance of economic cycles, we anticipate that power demand growth will be closer to recent levels during the baseline period and assumed an average rate of 5%/year.

The official plan for new capacity additions through 2006 is 17.5 GW over the baseline period, or the equivalent of an average annual capacity addition pace of 2,300-2,500 MW. About 40% is to be constructed by CFE while the balance will be available as BLTs. As of July 2001, the regulatory agency CRE had approved 177 plant permits for a total capacity of 15,200 MW – including 14 IPP projects (7.6 GW); 118 self-supply facilities (4.8 GW); and 36 cogeneration projects (2.1 GW).

The current capacity expansion plan includes a few hydro and geothermal plants, leaving the bulk - or 15.8 GW – as gas-fired additions. Most of this capacity is intended to be phased, combined-cycle plants in individual sizes ranging between 250 MW and 1,000 MW. This includes several projects already under construction such as Monterrey 3 (now expanded to a total capacity of 980 MW); Bajio (600 MW); Altamira 2 (495 MW); Tuxpan 2 (495 MW); Campeche (275 MW); and Saltillo (250 MW). There are also two projects sponsored by Alstom and Sithe Energies, Inc. that plan to use petroleum coke that will burn in a circulated fluidized bed.

Under development, we count at least seven plants, many of which are expansions of projects that are under construction. This includes Altamira 3 and 4 (1,036 MW total);

Chihuahua 3 (260 MW); Mexicali (600 MW); Naco-Nogales (340 MW); Rio Bravo 3 (495 MW); Rosarito 4; and Tuxpan 3 and 4 (980 MW total).

In addition, there are several cogeneration projects underway with a combined capacity of almost 3 GW through 2006: the Enron 284-MW project in Nuevo Leon; the 930 MW Electricidad de Veracruz project developed by Ispat, Kimberly-Clark and Iberdrola; the InterGen 90-MW Guanajuato project; the 260-MW Mexchem project sponsored by El Paso; the Toluca-Lerma 120-MW facility promoted by International Energy Partners; the 400-MW El Salto project also developed by International Energy Partners; and the 450-MW Cuernavaca project by Grupo Daviaz. Finally, Pemex has numerous cogeneration projects in planning (some say up to 10 GW).

Altogether, our database shows a total of 21 gas-fired CC projects under development for a total of nearly 11 GW. About 40% of that potential capacity is associated with projects in sizes between 400 MW and 500 MW. The balance is quite spread across project sizes that range from 500 MW to 1,200 MW.

It is interesting to note that current regulations now allow the development of "mixed" independent power plants that are part utility and part cogeneration. Some projects are now designed to provide 60-70% of their output to CFE and the balance to a group of industrials. This allows developers to achieve higher economies of scale even though the project is owned by two separate entities (the second one has to include the industrial users so that the second tranche of capacity can be construed to be industrial self-generation).

Our forecast is, however, lower since our view is that demand growth will be somewhat lower than the official forecast, and because we also expect Mexico to have some difficulties in bidding, financing and constructing new power plants. We project total new capacity additions at 10-14.5 GW for 2001-2006. For gas-fired capacity, we anticipate additions of 8.5-12.5 GW, the vast majority being gas-turbine-based (some of which will be cogeneration units).

In addition, the country wants to invest heavily in new transmission capacity and over 10,000 miles of high voltage transmission lines (69 to 400 kV) have been slated for construction over a 5-year period.

4.2.3 NGT Competitive Phase Outlook (2007-2020)

Whether or not a competitive power market develops in Mexico, there is strong internal demand for power and a strong desire to use new turbine-based plants to meet future capacity requirements. For environmental reasons, the objective is for natural gas, either domestic or imported, to play a much greater role in the power generation sector.

Long-term forecasts of power demand growth range from 3.5%/year to about 5%/year and we anticipate that demand growth will average about 4%/year. Depending on the extent of load growth and assuming a desire to maintain a nominal reserve margin of at least 10-15%, aggregate capacity requirements could range from 28 GW to 39 GW over the 2007-2020 time frame. Of this total, we estimate that about 23-30 GW (or about 70-80%) will be turbine-based gas-fired additions.

4.2.4 Market Potential Assessment

We forecast over the 2007-2020 period, CC/SC capacity additions between 23.5 and 31.25 GW. This includes a very strong pure power generation market of 17-20.25 GW, representing 73% of all projected gas-fired turbines orders. The only other notable market is the industrial cogeneration market that could add between 3.5 GW and 5 GW.

Based on a BIP mix that is definitely slanted toward baseload (44%), we projected the need for 21 GW of GT additions with average GT sizes as follows:

- 190 MW for pure power generation
- 143 MW for industrial cogeneration
- 61 MW for CHP and DG
- 219 MW and 225 MW for repowering

On that basis, we estimated that 40% of the forecasted GT capacity would likely involve GT units below 150 MW and that another 32% would be associated with turbines in sizes between 150 MW and 200 MW

Pure Power Generation. It is difficult to predict how the future Mexican wholesale power market will behave since it has not even been considered seriously yet. It is also reasonable to expect that the new exchange's governance and guidelines go through a couple of iterations, given the highly contestable nature of the Mexican market and the dominance of CFE.

Future dispatching of the Mexican wholesale power markets will be influenced by several factors:

- The large proportion of gas-fired combined cycles installed between 1998 and 2006
- Some transmission congestion issues between the East and West load regions
- The impact of a new power exchange
- The role of imports of power from the United States (there are several proposals to increase the interconnection capacity first to 2,000 MW and then double that goal)
- The competitive behavior of a broader slate of power generators as more large IPPs become involved in the Mexican market.

We anticipate a strong increase in price volatility in the Mexican market. As a result, the availability of a NGT-type technology would be quite welcome. In our estimation, about 26% of the projected GT capacity in that market segment would involve units below 150 MW and another 32% would be associated with GT units in sizes between 150 MW and 200 MW.

Industrial Cogeneration. Even after taking into account the current project pipeline, we still project an industrial CC/SC cogeneration potential between 3.5 GW and 5 GW over the 2007-2020 period. About 69% of the gas turbine demand in that market segment could use turbines in sizes below 150 MW but only 18% of the power output will be filling intermediate needs.

Combined heat and power (CHP). There will be limited opportunities in Mexico for this type of gas-fired application – between 250 MW and 500 MW over the 2007-2020 timeframe. They will, however, use smaller turbines, all below 150 MW. The average GT size in that segment is 61 MW.

Repowering. Opportunities will be very limited until some of CFE's thermal facilities installed in the 1980s become candidates. About 43% of CFE's current capacity –the equivalent of 15 GW – was built between 1981 and 1990; it is currently over 80% oil-fired. Nonetheless, repowering could start being attractive past 2015. We have projected a range between 1.5 GW and 2.75 GW; however, these applications are likely to use bythen turbines over 150 MW. However, 62% of the GT capacity in that segment could be associated with units between 150 MW and 200 MW.

IGCC. We also found a limited potential for IGCCs between 500 MW and 1,250 MW (about 2 baseload plants with large turbines in our median case). The average GT size is estimated at 225 MW.

Distributed Generation. Distributed generation applications over 30 MW will be limited until some distribution systems become interested to invest in peaking and intermediate capacity past 2010 to protect themselves against possible wholesale price fluctuations. In that context, we forecasted a DG range of 750 MW to 1,500 MW. Although small, this market segment can be addressed by turbines below 150 MW – the average GT size is estimated at 63 MW.

4.3 GERMANY

4.3.1 Market Evolution

Driven in part by directives from the European Union (EU) to introduce an integrated, competitive market to the EU and its member countries, Germany continues to move towards the development of a fully competitive wholesale power market.

In Germany, market liberalization began in 1998 and a fully competitive market should be in place by 2006. Two power exchanges (Leipzig and Frankfurt) started operating in 2000, each following a different approach. While LPX (Leipzig) is patterned after the NordPool's spot-hourly system (NordPool is part-owner in LPX), the Franfurt-based EPX is using different algorithms which are focusing on block trading.

Nonetheless, it will not take long before these two exchanges merge – maybe even before 2003. This will then be one more reason to believe that the result will soon be a large, liquid power market in place with a trading volume that could be around 1,500 TWh, supplemented by a broad derivative-based market.

Further on, Germany has the potential to become an attractive location for siting power plants and for selling power, as it will be at the intersect of more than 200 GW of wholesale power markets -- including the Netherlands, Belgium, France, Switzerland and Poland.

Extent of Deregulation. German deregulation opened the entire retail market all at once but the new law did not contain specific rules regarding transmission access and rates. Furthermore, the law did not originally set up an independent regulator.

The result was a strong price war both at the wholesale and retail level. Between 1998 and 2000, prices to industrials and even residential customers dropped by 10-20%. At the same time, wholesale prices tumbled by 30-40% as many municipalities played the market and renegotiated bilateral contracts.

When the wholesale price war started, some German municipalities asked for a quota for renewable and cogenerated power. In late 1999, the government agreed to provide a 5-year subsidy to municipalities whose supply featured at least 25% of coal-based cogenerated power. About a year later, the Government considered the use of a quota system to require that by 2010, up to 20% of all power used in Germany would come from cogeneration. The idea is still under debate.

Prices started to firm up in late 2000 and the introduction of the power exchanges started to bring the type of transparency that was needed. As a result, we expect a competitive wholesale power market to be in place at the beginning of the competitive phase.

The market is likely to include a subset of the 6 existing German IOUs (currently, E.On, RWE, Bewag, EnBW, HEW and VEAG) as mergers or takeovers are possible. In addition, the market will have many regional and international utilities and IPPs competing for new capacity and many power marketers competing for power sales. In addition, there are some municipalities with power generation assets who will participate.

Within a period of 2-3 years, the German market should be highly liquid and perhaps also fairly volatile as more and more foreign players trade and attempt to serve the retail loads which are in theory fully deregulated – except for customers in the service areas of municipalities (these can continue to act as single buyers through 2003).

During this phase, there will be increasing potential for new capacity to displace some of the existing coal-fired capacity controlled by the current incumbent utilities. Much of this could be gas-fired as gas will become more and more available during this period.

<u>*Environmental Issues.*</u> Environmental issues affecting nuclear and coal-fired power plants will have a major influence on the German power market during the NGT competitive phase. Nuclear (22 GW) and coal (over 50 GW) currently account for about two-thirds of Germany's power generating capacity.

The ruling Social Democrat party, elected in 1998, first announced that it wanted all nuclear power plants closed by 2005. It modified its stance and called for nuclear capacity to be retired at the end of current 30-year operating licenses, which would have retired all nuclear capacity by 2019. The nuclear industry threatened to sue unless the operating period was extended to 35 years. In early 2000, a compromise of 32 years was reached, under which nuclear capacity would be fully phased out by 2021.

Another controversial move by the government was to impose a 1.2 c/kWh ecology tax on electricity, oil, gasoline and natural gas. Another 1.2 c/kWh tax is to be added in 2003. Currently, high-efficiency, gas-fired cogeneration is exempt from the ecology tax, providing it with somewhat of an advantage to coal. It is likely that gas-fired capacity will remain somewhat favored; however, it is unlikely that gas will continue to remain entirely exempt from environmental taxation.

Given the amount of coal-fired capacity in place, and the importance of the domestic coal industry, it is also unlikely in our view that regulations and taxes on coal-fired power plants will become so onerous that they induce large-scale closures of coal-fired capacity.

The government has also favored the development of renewable energy. The last renewable law endorses the concept of a 6.7cents/kWh subsidy for wind power. As a result, some 6,000 MW of wind power capacity is currently in operation and another 2,000 MW may have come on line in 2001. Most of the new capacity is to be built in the inland regions of Lower Saxony. This level of activity is consistent with the German's government's intent to see the share of renewables grow from 5% to 10% by 2010.

Outlook for Energy Prices. Wholesale prices have already dropped significantly over the last 3 years and, through most of the baseline period (i.e., through 2004), wholesale power prices are likely to trend downward and stabilize around $27/MWh in 2003-2004 as the German market continues to gain in liquidity and cross-border power trading in Europe increases.

Prices should, however, firm up toward the end of the baseline period and the beginning of the competitive phase. By 2007-2008, wholesale power prices are likely tobe in the $29MWh range. From this level, we anticipate both a lowering of intermediate prices ($25-28/MWh) while peaking prices will retain volatility and hover in the $35-43/MWh range.

In similar fashion, natural gas prices in Germany should decrease from their recently increased levels of more than $3/MMBtu to $2.3-2.4/MMBtu through 20052007 as regional supply increases and as competitive natural gas markets develop in Europe. Overall, we expect that prices (in constant dollars) will remain in the $2-2.5/MMBtu range during the beginning of the competitive phase. Thereafter, prices will have the potential to increase as local and regional demand for gas increases, largely driven by increased requirements for power generation.

4.3.2 Baseline Period Projection

Despite its size (over 100 GW of installed capacity), the German power market should only see modest requirements for new capacity over the baseline period. First, power demand growth is expected to be quite modest at about 1-1.5%/year during the baseline period. Second, the country currently has a capacity surplus, with a nameplate reserve margin around 38% and an operating margin around 29-30%.

The result is that several previously planned combined-cycle IPPs were canceled, including the 2x1200 MW Lubin project, the 800 MW facility planned at Knapsack, and the 600 MW Kehlheim project. At this juncture, we have identified six CC projects that remain under development with a total capacity of nearly 3 GW. These projects tend to be around 300-400 MW – thus smaller than in many other European countries.

However, utilities are likely to retire some aging capacity (particularly that in the former East Germany). Although estimates vary, we believe that between 9 and 12 GW of capacity could be retired between 2001 and 2006. The utility E.On has been planning on retiring almost 5,000 MW in 2001-2002 while RWE's intent is to shut down some 4,100 MW between 2001 and 2004. By doing so, these two utilities would retire about 15% of their total capacity. RWE will replace some of that capacity with lignite plants (at the pace of one 1,000 MW unit every

2-4 years); the utility currently has 1,500 MW of new coal-fired capacity under consideration on two sites.

Thus, we project total new capacity additions of about 13-16 GW. Some of that capacity will be using renewable energy. Even after the substantial wave of wind power capacity additions during the past 3 years, we estimate that another 4,500 MW could come on line between 2002 and 2006 – including some offshore projects since some 15 projects with a combined capacity of 10,000 MW have been announced in the past 12-15 months.

There may also be about 1 GW of cogeneration capacity but new plans have been slowed down lately as the result of wholesale price declines. As a result, we project gas-fired capacity additions of 4-8 GW, including about 2-4 GW of new merchant capacity.

4.3.3 NGT Competitive Phase Outlook (2007-2020)

We expect that long-term power demand growth will remain relatively modest in the 1-1.5%/year range. High-end projections are only about 2%/year. Given the current oversupply situation, the modest growth rates expected during both the baseline and competitive periods means Germany is not expected to have major requirements for new capacity. The biggest variable during the competitive phase will be whether or not nuclear capacity is actually retired as is currently planned.

Our forecast is for about 20-35 GW of total capacity additions, including about 10-22 GW of gas-fired capacity. The low end of these ranges would reflect a future where only about one-half of the nuclear capacity is retired by 2020 with the more efficient capacity ultimately allowed to operate a few more years than the current 32-year agreement. Still, probably by 2025 and perhaps sooner there could be needs for another 12 GW of capacity, of which a large fraction would probably be gas-fired. This high-end forecast assumes higher growth and more retirements.

4.3.4 Market Potential Assessment

We forecast, over the 2007-2020 period, a total gas-turbine market between 12 and 26 GW. This includes a moderately strong pure power generation market of 4.5-9.5 GW, representing 42% of all projected gas-fired turbines orders. The other markets will each contribute far less each but their individual shares tend to be similar, all between 9% and 14%. As a result, Germany turns out to be the most balanced KTM market outside of the United States.

We projected 14 GW of GT capacity additions in our mid-case with the following estimates of average GT size:

- 225 MW for pure power generation
- 168 MW for industrial cogeneration
- 118 MW for CHP and 89 MW for DG
- 240 MW for repowering and 265 MW for IGCCs

Overall, we find that 34% of the GT capacity could involve units below 150 MW and another 21% would be associated with units between 150 WM and 200 MW.

Pure Power Generation. Future dispatching of the German wholesale power markets will be influenced by several factors:

- The large amount of coal-based capacity (45 GW, including 20 GW of lignite) that is in place
- The progressive phase-out of 22 GW of nuclear power (even if not all that capacity ends up being retired)
- The relatively small importance of hydro (less than 9,000 MW in place)
- The level and location of plant retirements past 2008-2010 (which could range between 6 and 12 GW)
- The role of wind – as much as 12,000 MW could possibly be on line by 2010
- The changes in dispatching from almost 15,500 MW of large industrial cogeneration capacity (a third of that capacity could sell excess power)
- The impact of continued transmission congestion issues between the East and West load regions
- Changes in cross-country power trading and thus imports from France and Switzerland into Italy. It will take another 2-3 years to find out how the European power exchanges may be operating (i.e., the two German exchanges that are likely to merge, the new French exchange - PowerNext – and the new Italian exchange)
- The competitive behavior of a broad slate of power generators since the German market will attract the largest population of players in Europe.

We anticipate an increase in price volatility in the German market for the 3 years to come and our market simulations show that a substantial share of the German baseload and intermediate market will end being dispatched at lower prices in the 2010 decade. The current load curve shows quite an increase past the first 25 most economic GW – the dispatch price then increases from less than 10 euros to 22 euros. As a result of further deregulation and more efficient capacity additions, we anticipate an increased market competition.

As a result, the next 45 most efficient GW will be dispatched at below 20 euros past 2010 – the average price decrease will be between 4 and 7 euros. At the same time, about 10-12 GW of peaking capacity will either become obsolete or be forced to dispatch at rates that could be 10-15 euros less than currently.

This will have several implications:

- We project a low share of baseload gas-fired capacity additions during the competitive period – only 29%
- The share of intermediate gas-fired capacity additions could be quite high – possibly as high as 41%. There will also be a repowering market that could contribute almost 15% of all new gas turbine capacity ordered during the competitive period.

- The demand for peaking gas-fired additions will remain quite strong, as high as 31% in our estimate, in spite of the dampening impact that projected wind power capacity additions will have.

About 70% of that power-only capacity will involve simple-cycle plants. However, we also expect that a large number of merchant power producers will opt for large gas turbines. This leaves only 19% of the projected needs in new pure power generation capacity to be addressable by turbines in individual sizes below the 150 MW threshold. However, an additional 30% of the forecasted GT capacity could be met by units between 150 MW and 200 MW.

Industrial Cogeneration. In Germany, cogeneration contributes 10% of electrical capacity, divided between the industrial and district heating sectors. This includes about 14,500 MW of industrial self-generation or cogeneration; in addition, there are over 8 GW associated with district heating loops (many in the previously East Germany). Since 1998 when a fierce wholesale power price battle started, cogeneration project development activity has considerably slowed down. In fact, many existing plants either shut down or were mothballed.

The activity is not completely out, however, since there is currently at least 380 MW of cogeneration under construction and another 140 MW under development. In addition, there are 1,600 MW of combined cycle projects designed to sell their outputs to both industrial owners and the local grid. They generally are based on three trains in 2x1 configurations.

We expect the industrial cogeneration activity to increase again when capacity margins have sufficiently decreased, probably by 2006-2008. We project opportunities for cogeneration plants over 30 MW at between 1,500 MW and 3,500 MW between 2007 and 2020. Although an increasing share of the new cogeneration project capacity could involve large GT trains using 250 MW and even 350 MW machines, about 61% of the projected gas-fired cogeneration orders would still involve gas turbines in sizes below 200 MW.

Combined heat and power (CHP). There are significant opportunities to install CHP units in district heating areas. Germany has more than one hundred municipality-owned or operated district heating systems in place. Many German municipalities are likely to be interested in building CHP units to optimize their energy use. Over the 2007-202 period, we have projected between 1 GW and 2.5 GW of CC/SC capacity additions in this segment.

Based on their likely dispatch costs and their technical/operating constraints, we estimate that about 80% of the power output of these systems will end up being sold as peaking or intermediate power when power prices can be the highest. To do so and yet accommodate their own captive needs, these CHP applications will prefer to have multiple gas turbine units. Finally, we estimate 84% of the GT units involved in CHP applications will be below 150 MW and 100% below a 200 MW individual size. These three factors indicate that this could be a good NGT-like market segment.

Repowering. Opportunities will be limited to the less than 4-5 GW of oil-fired capacity that the incumbent utilities may still have under their control past 2007. We estimate that between 2 and 4 GW of repowered capacity could come on line between 2007 and 2020. However, we also foresee that only 21% that capacity would involve turbines in individual sizes below 150 MW and 41% below 200 MW. The projected average GT size is 240 MW in this type of application.

IGCC. The potential for IGCC applications in Germany could grow past 2012-2015 and we have estimated that between 2 and 4 GW – or the equivalent of about 4-8 projects - could come on line by 2020. However, we also project that all this capacity would most likely involve turbines in individual sizes above 200 MW. For that reason, we have estimated an average turbine size of 265 MW in that market segment.

Distributed Generation. A growing number of distribution companies may become interested in investing in distributed generation facilities to protect themselves against potential wholesale price variations. In addition, we forecast that between 12 and 15 energy retailers (some German but an increasing fraction European) will pursue the German retail market and will invest in DG solutions to back up their retail loads. We have projected the potential for between 1 GW and 2.5 GW of plants that will range between 30 MW and 150 MW. About 65% of these will be simple-cycle peaking plants.

4.4 ITALY

4.4.1 Market Evolution

A competitive market should develop in Italy over the baseline period, following the general guidelines set by the EU. Indicative of this development is the creation of an independent grid management company in 2000, the creation of a wholesale power pool which should be operating by 2002 and the creation of at least three independent GENCOs (with a combined capacity of 15 GW slated for sale before the end of 2002) to be spun-off from the national electricity utility (ENEL). Edison won the assets (5.4 GW) of Elettrogen and the assets of Eurogen (7 GW) are next to be auctioned. The third auction (Interpower with 2.6GW) should take place before the end of 2002. Finally, there was increasing support during the last four weeks of 2001, for one more divestiture sale by ENEL (probably in the 4-5 GW range).

After the 3-4 divestitures, ENEL will still be the predominantforce in the Italian power market, with a market share that could range between 65% and 70%. However, competition for new capacity will progressively increase between ENEL, a rising number of IPPs and the newly created GENCOs. Furthermore, some of the generating capacity that was owned by several large industrial companies has already been targeted by European utilities. In particular, EdF – in cooperation with Fiat through the newly formed Italenergia group - was able to acquire the asset portfolio of Montedison which is in turn in the process of combining its assets with those of Sondel – the result will be the EdF's virtual take over of 5,100 MW of assets.

As a result, ENEL's share should drop below 60% by the end of the baseline period.

Extent of Deregulation. The deregulation of the wholesale market is behind that of the retail sector where eligible customers (e.g., customers with annual loads above 20 GWh) are free to shop around. To do so, they have entered into bilateral contracts with generators and distributors, while waiting for the initial stages of Italy's competitive wholesale power exchange (PE) market to be in place probably in early 2002. The new PE will start with a day-ahead market exchange combined with two "intra-day" markets each with different lead times of a few hours.

Customers with loads of 9 GWh/year will be eligible in 2002 and all customers may be free to choose by early as 2005. Yet, a truly competitive and liquid wholesale market will take time to develop. Nonetheless, such a market should be in place near the beginning of the competitive phase. ENEL will be the largest player, but its market share will continue to be reduced, as IPPs and the independent GENCOs grow. The number of power marketers competing in the market will also increase.

Environmental Issues. Italy's aim is to increase the use of natural gas and renewable energy to meet its environmental objectives; therefore, there should be no major impediments for gas-fired power generating systems.

Future issues surrounding nuclear and coal-fired power generation should not substantially influence the outlook for gas-fired generation:

- Italy has four nuclear power plants that have been idle since 1987 when the country voted against the use of nuclear power. There is no expectation that nuclear power generation will be rekindled during the NGT competitive phase.
- Italy also has about 11 GW of coal-fired capacity and net changes to the installed base should not have a material impact on the future market during the competitive phase. We expect some increase use of coal-fired generation, but do not see a major increase in coal generation given that coal has to be imported and taking into account coal generation's likely relative economics including environmental taxes. Whether coal generation is marginally expanded, or is marginally reduced (from heavier than expected taxation), the future potential for gas-fired capacity should not be greatly influenced.

The Italian government has also called for the increased use of renewable energy. The so-called Framework Decree stipulates that a minimum of 1% of total power be supplied from renewable resources. Furthermore, large generators (i.e., with outputs above 100 GWh/year) are required to source at least 20% of their supplies from renewable energy.

Outlook for Energy Prices. Current wholesale prices are high and are attracting market entry and project announcements. However, wholesale power prices are likely to drop to the $30-33/MWh range in 2003-2004 following the opening of the market to competition and as regional power trading in Europe increases. In addition, incumbents who can receive compensation for stranded costs will retain a competitive advantage as they will be able to afford to undercut prices.

From this level, prices are likely to stay around $33/MWh in 2007. Intermediate prices are likely to hold in the $30-35/MWh range and peak prices show high volatility ($36-45/MWh).

Natural gas prices in Italy should be quite similar to those in Germany, in fact prices across the EU should tend to equilibrate in the $2-2.5/MMBtu range. Generally, prices are expected to decrease marginally from current levels until the beginning of the competitive phase as regional supplies increase, but to then gradually increase as regional demand increases -- driven by growing requirements for intermediate and peaking power generation.

A key issue for Italy is a need to diversify is gas supply sources. Gas consumption is mostly met by imported gas, with over 50% of Italy's gas supplied by Algeria and Russia. Because of the expected large increase in gas use, much of it for power generation, the country is trying to diversify its supply options and is investigating imports from Libya, Norway and Nigeria.

4.4.2 Baseline Period Projection

Even though there is nearly 75,000 MW of proposed capacity under development, there are quite divergent views regarding the outlook for the Italian power market during the baseline period. Some sources see an oversupply through 2010 and perhaps beyond, while others see as much as 7-10 GW needed over the next 5-10 years and potential shortfalls appearing within the next 2-3 years. In our view, these quite different views can be rationalized based on different assumptions regarding future demand growth and based on different views regarding the availability of current capacity.

In terms of power demand growth, Italy averaged an annual increase of 7.5% from 1995 to 1998, but since then demand growth has slowed. Lower demand growth would support the view of modest to no new capacity requirements over the baseline period, while forecasts of near-term capacity shortages would seem to be based on expectations of a return to strong demand growth.

In terms of capacity availability, Italy's nameplate reserve margin in 1999 was over 40%, but its operating margin was often just over 10%. The high nameplate margin suggests little new capacity requirements, while the low operating margin would indicate a need for capacity and the potential for near-term shortages.

We believe that demand growth is more likely to maintain current levels, in the 3-3.5%/year range, than to return to annual growth rates of at least double that level. We also expect that the move towards competition and deregulation will help spur improvements in current units improving overall availability.

We have also examined the current project backlog and determined that there is a realistic project pipeline of about 25 projects with a combined capacity of 22.5 GW. A fairly large proportion (over 30%) of these projects are in the 800-900 MW range while there are 3 huge projects of more than 1 GW each. The balance consists of about 10 projects between 100 MW and 600 MW.

On this basis, we project total new capacity additions of about 6-10 GW, including about 4-7.5 GW of new gas-fired power generation capacity for 2001-2006. Only 400-500 MW of additional renewable capacity is projected. Future cogeneration capacity additions will represent the balance (about 1.5 GW); in addition some large cogeneration units (another 1.5-2 GW) will also sell merchant power to the grid.

In addition to modest opportunities in new plants, gas turbines will also see opportunities involving oil-to-gas conversions. ENEL has planned over 14 GW of such conversions by 2007 and possibly another 6 GW between 2008 and 2011.

4.4.3 NGT Competitive Phase Outlook (2007-2020)

The current issues of demand growth and capacity availability will also be issues that influence the long-term outlook for capacity requirements. The need and potential for new gas-fired capacity will also be influenced by the extent to which Italy is able to follow through on plans to develop renewable energy resources. Our outlook for aggregate and gas-fired capacity additions is based on four main assumptions:

- We anticipate that long-term power demand growth will moderate even further from current levels and will average about 2-3%/year during the NGT competitive phase.
- Capacity availability will be improved to the 85-90% range, compared to only about 80% now, creating an increase in available capacity of about 5-8 GW –most likely between 2007 and 2011 as new power generators increasingly streamline their power asset portfolios.
- The government plans for 7 GW of renewable capacity by 2012 will not be fully met; instead, it may only reach 50-60% of that target. Gas will thus remain the favored fuel to meet environmental objectives.
- In line with those objectives, gas-fired CT/CC plants can be expected to account for 60-65% of total new capacity additions. There are plans to increase gas purchases from current suppliers (especially Algeria) and bring new LNG supplies from Norway, countries around the Mediterranean and the Middle East.

On this basis, we project total new capacity additions of about 22-31 GW over the NGT competitive phase. New gas-fired capacity additions are projected to total about 12-22 GW. Capacity additions could, however, be higher if the amount of capacity that is economically displaced could reach the 5-9 GW level.

4.4.4 Market Potential Assessment

We forecast over the 2007-2020 period, CC/SC capacity additions between 13.5 GW and 24.5 GW. This includes a moderately strong pure power generation market of 6 GW to 8.75 GW, representing a potential share of 44% of all projected CC/SC additions. The other notable CC/SC markets will be repowering (15% share), distributed generation (13%) and industrial cogeneration (11%).

Given a projected BIP mix of 36% peaking, 38% baseload and only 26% intermediate, we anticipate 15 GW of GT capacity additions to meet projected CC/SC additions.

Overall, we found that the average sizes for various applications would be:

- 212 MW for pure power generation
- 177 MW for industrial cogeneration
- 119 MW for CHP
- 229 MW for repowering
- 267 MW for IGCCs
- 80 MW for distributed generation.

We further estimate that, out of that amount, 5.7 GW (39%) of GTs could involve units below 150 MW and 9.1 GW (61%) would likely be associated with units that are below a 200 MW individual size.

Pure Power Generation. It is difficult to predict how the future Italian wholesale power market will behave since it has not started yet. It is also reasonable to expect that the new exchange's governance and guidelines go through a couple of iterations, given the highly contestable nature of the Italian market.

Nonetheless, future dispatching will - at least in the first years of the competitive phase - be influenced by several factors:

- The importance of hydro (about 16,500 MW in place)
- The aging and conversion of up to 15,000 MW of oil-fired capacity between 2001 and 2010
- The change in cross-country power trading and thus imports from France and Switzerland into Italy. It will take another 2-3 years to find out how the European power exchanges may be operating (i.e., the two German exchanges that are likely to merge, the new French exchange - PowerNext – and the new Italian exchange).
- Changes in load utilization rates in some new large (500-800 MW) combined cycles brought or expected to be brought on line during the 2001-2006 period
- The changes in dispatching from almost 7,000 MW of industrial self-generation capacity as some of that capacity may change hands and be remarketed by traders (currently under long-term contracts, generally signed between 1985 and 1996)
- Transmission congestion issues between the North and the South
- The competitive behavior of a broader slate of power generators since many European companies have indicated their strong intentions to participate in the Italian market.

Although we anticipate an increase in price volatility in the Italian market for the next years to come, our market simulations have shown that the Italian market has the potential to grow in a quite harmonized way where long-term arbitrage opportunities may actually be restrained. When we compare the current power load curve with what that curve may look likein 2020, we see the potential for an across-the-board price pressure of 3-4 euros but no substantial change in shape.

This means that we can predict a more balanced market with a relatively strong baseload share (38%). However, the intermediate market is likely to be somewhat "squeezed" with many coal units that will increasingly have to cycle their operations. Consequently, we forecast that new gas-fired intermediate load additions will only account for 28% of the forecasted gas turbine order activity during 2007-2020. There will, however, be an increasing demand for peaking gas-fired capacity past 2010 (after the impact of the new wind power capacity additions will have started to fade).

In this pure power generation market, we expect, in our mid-case, 6 GW of GT capacity added between 2007 and 2020. We also forecast that 31% of the pure power capacity will be associated with turbines in sizes below 150 MW and that another 23% of GT capacity would involve GT units between 150 MW and 200 MW.

<u>Industrial Cogeneration.</u> In Italy, cogeneration currently supplies about 16% of electricity. This includes some 10,000 MW of industrial cogeneration capacity, most of it from large scale industrial plants that were developed in the past 8 years as the result of several favorable

laws. About 8 projects (1,200 MW) were developed over the past two and a half years, several of which were developed by Edison, Sondel and Fiat Avio. The largest facility was built in Ternia, Umbria: this is a 1,000 MW merchant cogeneration project that sells its output to several industrial customers. In addition, there is a 284 MW heavy-oil syngas combined cycle gasification project that involves the participation of Texaco. In fact, this is the third large IGCC project (the two others are in operation at Sarlux and Prioro Gargallo).

However, new project announcements have slowed down with the pending opening of the wholesale market. Furthermore, there are no support measures currently used or planned. This situation will however change after the first wave of merchant power projects (through 2005-2006) and the first cycle of price cuts. At that juncture, some cogeneration sites will become attractive again. Many of these may however sell some of their output on a merchant basis. Nonetheless, we project an industrial cogeneration market of about 1.5-3 GW for the 2007-2020 period. This translates into nearly 2 GW of GT capacity in our mid-case, out of which 45% would likely involve gas turbine units below 150 MW and another 22% would be associated with GT units between 150 MW and 200 MW.

Still, some projections (by the European Cogeneration Association) have shown that, under a Kyoto-type scenario, the market for industrial cogeneration could increase up to 10 GW for all plant sizes (7. 7 GW for plants over 30 MW).

Combined heat and power (CHP). Opportunities for CC/SC-based CHP applications above 30 MW over the 2007-2020 period are estimated at between 1 GW and 1.75 GW. Some of these opportunities could be associated with possible projects by municipalities (e.g., Milan, Turin) who want to hedge against wholesale price fluctuations and have district heating systems.

This would translate into 1 GW of GT additions. In our estimation, about 82% of that market segment could rely on gas turbines in sizes below 150 MW. Most of the excess power will be sold as intermediate or peaking at times when the power prices can be the highest. These applications will prefer to have multiple gas turbine units.

Repowering. Opportunities will be first limited to the 4-6 GW of oil-fired capacity that ENEL controls – but several projects may already have taken place prior to 2007. Past 2010, some plants built in the 1980s may become candidates, though. Over the 2007-2020 period, we estimate the repowering CC/SC potential at 2-5 GW.

This market segment will probably end up being fairly evenly divided between baseload and intermediate use, given the possible location of these ENEL or earlier power plant units. Furthermore, 94% of the associated GT demand is likely to rely on gas turbines larger than 150 MW – while 57% would be for units in individual sizes above 200MW. Configurations could be either 2x1 or 1x1.

IGCC. The potential for IGCC applications in Italy could grow past 2012-2015 and we have estimated a potential market between 1.5 and 2.5 GW during the NGT competitive phase. We forecast, however, that over 80% of that segment will target baseload usage and that all IGCC plants are likely to involve gas turbines larger than 150 MW or even 200 MW.

Distributed Generation. We foresee a potential between 1 GW and 3.5 GW in DG projects over 30 MW. This activity is likely to start past 2010 and will be spurred by the desire of distribution companies, municipalities and future retailers to protect themselves against potential wholesale price variations. Over 80% of that capacity will be for intermediate or peaking production. Furthermore, this DG activity will involve gas turbine units below the 150 MW size threshold.

4.5 SPAIN

4.5.1 Market Evolution

Like the other members of the EU, Spain is moving to institute a deregulated, competitive power market. A mandatory U.K.-style wholesale power pool was first started in 1998 and a fully liberalized, competitive market was planned to be in place in 2007. Since then, the deregulation process and deadline has been accelerated several times – first to 2005 and now the market is more likely to be fully opened by 2003-2004. At the same time, the gas industry is also being deregulated.

The Spanish power market currently includes local IOUs (four main incumbents) and independent power companies, but because of extensive cross-ownership among the IOUs current market rules are producer-oriented. Currently, the Spanish power generation market is in essence a duopoly controlled by Endesa (with 22 GW of capacity) and Iberdrola (16 GW).

Extent of Deregulation. The wholesale market in Spain is currently administered through Operadora del Mercado Espanol de Electricidad (Omel) while the operator of the transmission system is Red Electrica (which is jointly controlled by the utilities, each originally with 10% and the central government, with 28.5%.

A new system is likely to be in place around 2003-2004 and an increasingly liquid market with at least 2-3 years of operating history can be expected to be in place by the end of the baseline period. By then, the generation industry landscape may have further changed as the result of the impacts of divestitures or mergers as well as further regulatory actions.

In the past two years, there were several merger or takeover attempts involving Endesa, Hiberdrola and Hidrocantabrico. In particular, Endesa and Iberdrola had planned to merge but Spanish regulatory authorities would approve the deal unless the two companies committed to a significant auction-based divestiture program (about 16 GW), lowered their stakes in both OMEL and Red Electrica and accepted a high degree of regulatory oversight. The regulators did not want the combined entity control more than 42% of the Spanish generation market and expressed the desire to see at least two new significant generators enter the Spanish market.

In the meantime, Electricidade de Portugal (EdP) and Energie BadenWuerttemberg (EnBW) invested in Hidrocantabrico; however, EdP's and EnBW's voting rights were limited by Spanish regulators.

Additionally, to even the field, the Spanish government blocked any generator with a market share over 40% of adding capacity for five years (through 2005) and any generator with a share of more than 20% cannot add any capacity through 2003. As a result, Endesa had to limit the growth of its plant generation program and decided to divest 2.6 GW of capacity to allow it to build a program of more efficient combined cycles.

Once the Spanish industry structure is more balanced and the new wholesale market system is put in place, both generators and energy retailers (the later serving as intermediaries between generators and end-users and/or distribution companies) are expected to be allowed to bid. Power pricing is likely to be based on hourly merit-based dispatch. Power will initially be sold through both bilateral contracts and spot market transactions, although the later will increase throughout the period. Finally, competition for new power plants should come from the incumbent IOUs and new IPPs (mostly gas companies and subsidiaries of European electric utilities).

Environmental Issues. Spain's energy programs and policies should continue to favor natural gas and the use of gas will increase if subsidies are reduced or removed on domestic coal production.

Like Germany, future issues affecting nuclear and coal-fired power plants will influence the outlook for the Spanish market; however, these impacts would not be of the same magnitude since only about one-third of Spain's current generating capacity is either nuclear (over 7 GW) or coal-fired (about 11 GW), compared to about 70% in Germany.

The future of Spain's nuclear capacity has been less debated than Germany's; we assumed, however, that nuclear plants will be retired as their operating licenses expire -- which would result in 6 GW of capacity closings by 2020. While gas is expected to be the fuel of choice in Spain, coal use will continue, although at reduced subsidy levels, to support domestic production.

In addition, Spain has engaged on a very aggressive renewable program that resulted in the development of close to 3,300 MW of wind power capacity. This development was prompted by the availability of a substantial subsidy equal to either a fixed payment of 0.0626 euro/kWh or a premium of 0.028 euro/kWh on top of the average wholesale market price. In this context, it is not surprising that some 2, 270 MW of wind power was developed in the past four years. In 2000, capacity additions neared 800 MW and another 800 MW was expected for 2001. According to APPA, the Spanish Renewable Energy Producers Association, there is another 2,400 MW under development. Furthermore, it is reported that planning permission has been sought for a total of 25,000 MW of wind power capacity.

Outlook for Energy Prices. Resulting from some oversupply and increased competition, wholesale power prices should decline from current levels to about $25/MWh in 2003-2004. Such decrease will also happen in response to the government's pressure to reduce electricity prices both at the wholesale and retail levels. From that level, wholesale power prices are likely to be around $27/MWh by 2007. With increased competition, intermediate power prices will stay within $27-30/MWh and peaking prices will range between $33-40/MWh. Price changes will also tend to reflect changes in fuel and other operating costs.

Spain's long-term natural gas prices should decrease from today's $2.7-3 /MMBtu to $2.3/MMBtu for most of the 2005-2008 time window. We expect long-term prices (post 2008-1010) to remain quite competitive, since we see Spain developing into a regional gas hub for Europe, in particular importing and trading gas from North Africa.

4.5.2 Baseline Period Projection

Spain has been one of the most rapidly growing EU markets, with power demand increasing 5.5-7%/year recently. We anticipate that Spain's power demand growth rate will slow somewhat and average about 4-5%/year during the baseline period.

Nonetheless, the government has been concerned that a California-style situation could arise and that not enough capacity may be added. These fears were confirmed during this winter when record cold weather caused blackouts and forced the government to put in place on December 18, 2001 a rationing plan.

Consequently, Spain's Economy Ministry will be eager to implement the energy plan that it published in 2001 and called for accelerating new plant authorizations. Clearly developers answered the call for action since our proprietary PA International Power Data Base shows that, as of November 2001, there were 54 combined-cycle projects announced with a combined capacity of 33,600 MW. At the same time, some developers are being forced to scale back their plans due to opposition by municipality governments and environmental protection groups. Yet, our database shows that there are 54 projects under way, representing a combined capacity of 34 GW. About 30% of that capacity involves projects in the 800-900 MW range and 25% is associated with projects that are above 1 GW in size. The balance of the backlog consists of some 14 projects in sizes between 400 and 500 MW and nearly 10 projects below 400 MW each.

The government, which had approved some 4.8 GW in 2000, approved another 3,200 MW in 2001.Now, some 3,200 MW of gas-fired capacity should be commissioned in 2002 and another 3,600 MW is slated to come on line in 2003. In parallel, the government moved to ensure an orderly increase in wind-power capacity additions.

Depending on load growth, gas availability and the extent of future coal subsidies, total new capacity additions through 2001-2006 are likely to range from about 10 GW to 12.5 GW. Of the total additions, we anticipate that some 3.5-4 GW will involve wind power, cogeneration and waste-to-energy capacity additions. This estimate is lower than some forecasts that predict between 2001 and 2010, up to 6,000 MW of additional wind-power capacity and 2,500 MW of additional waste-to-energy power capacity.

This will leave 6.5-8.5 GW of gas-fired capacity additions, including at least 4-7 GW of merchant-oriented plants. This is similar to Red Electrica's forecast that gas-fired capacity additions through 2005 could range between 5,600 MW and 7,200 MW; the transmission company forecasted an additional 4,400-6,400 MW for the period 2006-2010. This implies an annual average level ranging between 1,000 MW and 1,350 MW.

A key variable in the outlook for gas-fired power plants is the future competitiveness of coal-fired generation. Coal is Spain's main indigenous energy resource and while it is too expensive to compete in a deregulated market, it has been subsidized to protect the domestic coal industry. During the baseline period, we expect that the Spanish government will continue to act to protect its coal industry – it has previously opposed EU plans to tax coal, limiting to some extent the upside potential for new gas-fired capacity.

4.5.3 NGT Competitive Phase Outlook (2007-2020)

From the 4-5% yearly growth projected for the baseline period, we expect long-term power demand growth to moderate to about 3-4%/year during the NGT competitive phase. In addition, up to 6 GW of nuclear capacity could be retired over the period. Furthermore, Spain's Environment Minister expressed its intention in late 2000 to see the phased closure of 12 of the country's most polluting coal-fired plants by 2010 to satisfy European Union environmental commitments. Finally, there are some oil-fired plants (out of an existing capacity of about 10 GW) that will be candidates for economic retirement.

To meet this growth, and to offset these possible retirements, total capacity requirements could range from about 24 GW to 37 GW. New gas-fired capacity additions are projected to total about 16-27 GW.

A major uncertainty in the outlook for gas-fired capacity is the long-term potential for coal, renewable and waste-to-energy (WTE) generation. As mentioned, coal is currently only economic because of subsidies for domestic production. For renewable and WTE generation, some government plans call for the development of upwards of 15 GW by 2015. We do not expect nearly so much renewable capacity to be added; however, the expanded use of renewable energy sources would diminish the prospects for gas-fired generation.

On the other hand, some coal capacity could be economically displaced by more gas-fired capacity. Thus the negative impact of a possible increase in renewables on future gas capacity additions could easily be offset by 3-10 GW of coal-fired or oil-fired capacity displacement.

4.5.4 Market Potential Assessment

We forecast over the 2007-2020 period, CC/SC capacity additions between 17 and 29 GW. This includes a very strong pure power generation market of 11.5-17.8 GW, representing a potential share of 68% of all projected CC/SC additions. The other notable markets will be industrial cogeneration (9%) and repowering (8%).

In our mid-case, we projected the need for 18 GW of GT capacity, based on a even BIP mix (34% for intermediate and baseload needs and 32% for peaking). Out of that amount, we estimate that 5.6 GW (32%) would involve GT units below 150 MW and 10.3 GW (58%) would be associated with units below 200 MW.

We found that the average sizes for various applications would be:

- 215 MW for pure power generation and industrial cogeneration
- 95 MW for CHP
- 228 MW for repowering
- 231 MW for IGCC applications
- 77 MW for distributed generation.

<u>Pure Power Generation.</u> It is difficult to predict how the future Spanish wholesale power market will behave since its next version (to be in place probably in 2003-2004) is not yet well

defined and subject to many potential debates and challenges, given the very competitive and oligopolistic nature of the power industry.

Nonetheless, future dispatching will - at least in the first years of the competitive phase - be influenced by several factors:

- The importance of hydro (about 20,000 MW in place)
- The role of wind – as much as 6,000 MW possibly by 2010
- The aging of some of the early phase of combined cycles and merchant plants that have come on line between 1999 and 2003
- The change in load utilization in many large (500-800 MW) combined cycles brought or expected to be brought on line during the 2001-2006 period
- The changes in dispatching from almost 4,000 MW of large industrial cogeneration capacity commissioned between 1998 and 2002
- Continued discontinuities in power planning policies among various provinces (e.g., Basque, Catalonia or Valencia regions)
- Transmission congestion issues (there is a need to increase transmission capacity between Spain and both France and Portugal)
- The increasing possibility that by 2006-2007, the Spanish and Portuguese grids will be increasingly tied (even if there have been some strong political currents against, the economics may prevail later in the decade)
- Increasing competition from a broader slate of power generators since many European companies have indicated their strong intentions to participate in the Spanish market.

As a result, we anticipate an increase in price volatility in the Spanish market for the next 3-5 years and our market simulations indicate that Spain's power load curve will substantially change between now and 2020:

- Up to 10 GW of baseload market will fall under increasing pressure to drop prices by 10-15 euros/MWh or shut down
- Another 15-20 GW of new baseload and intermediate capacity will come on line at dispatch prices generally between 18 and 25 euros
- The 7-8 GW of expensive power that is now bidding at prices over 30-35 euros/MWhs will have to bid 5-10 euros lower

This means that we can predict a very balanced market with even shares (in the 32-24% range) for baseload, intermediate and peaking capacity additions in order to address the three parts of the supply curve.

In this context, we project a CC/SC pure power market between 11.5 GW and 17.8 GW. Although 56% of the pure power project capacity will involve peaking units, merchant power producers will tend to opt for large gas turbines – only 27% of the project capacity (about 3.2

GW) is likely to use turbines in sizes below 150 MW. However, some 55% is likely to be associated with units below 200 MW.

Industrial Cogeneration. In Spain, the potential for CC/SC additions in industrial cogeneration has been estimated at 1.5-3.2 GW over and beyond the 4.75 GW of already installed industrial cogeneration capacity. Industrial cogeneration (especially gas-fired) expanded rapidly in the 1990s when some 3.2 GW of gas-fired cogeneration projects came on line within a period of 5 years. These cogeneration projects were developed by companies like Ecyr, Endesa Cogeneracion, Energy Works, Gas Natural, Iberdola Cogeneracion, Union Electrica Fenosa Cogeneracion, Solvay Iberica and Tomen.

There is a fair amount of cogeneration projects under way – as many as 2,200 MW under development as of November 2001. This includes several large cogeneration units planned to be built on refinery sites (e.g., Gibraltar refinery, a Petronor refinery, the Dow La Seda petrochemical complex, the BASF Tarragona plant).

Nonetheless, some large combined cycles have been proposed and are under construction by companies like Endesa, Gas Natural, Hidrocantabrico, and Iberdrola; these projects (most of which are in the 800 MW range, including two 400-MW blocks) are designed to sell electricity both to industrial users and the grid. These facilities are thus merchant plants competing with what would be otherwise cogeneration plants. At this juncture, some 2,400 MW of that type of capacity is under way and scheduled to come on line in 2002 alone.

Between 2007 and 2010-11, additional industrial cogeneration may be more limited in part because some of the market will have been equipped and otherwise due to tough competition with wholesale power prices. In addition, some decentralized generation will still be expected to come from wind power (possibly about 2 GW in these 4-5 years even if the market has become somewhat saturated and subsidies have been partially cut).

Past 2010-11, however, some cogeneration sites are likely to become attractive as the power sector may then encounter another price cycle. An increasing number of cogeneration plants will then sell some of their output on a merchant basis. As a result, we forecasted that 43% of the cogeneration plant capacity additions would involve turbines in individual sizes below 150 MW and 63% of the GT capacity would otherwise be associated with units below 200 MW.

Industrial cogeneration would, however, increase further if environmental benefits can be taken into account. For example, a European Commission report projected a cogeneration potential increase of 3.7 GW (in all sizes) between 2007 and 2020 but the bulk of that increase (about 3 GW) was forecasted to occur past 2015. In all other scenarios (including even one environmental friendly scenario), the projected increase is less than 500 MW over that time frame.

Combined heat and power (CHP). The CHP market lourished somewhat in the mid-1990s with several applications in the 1-10 MW range for hospitals and commercial estate centers. However, opportunities for applications over 30 MW have been quite limited. We estimate the CHP-related CC/SC market at only 0.5-1 GW for the 2007-2020 period, assuming that retail companies and ESCOs opt to be actively involved in CHP projects. All these projects are, however, likely to use turbines below 150 MW and most of their excess sales will meet intermediate power needs.

Repowering. Opportunities will be limited to the 10 GW of oil-fired capacity that is in place. However, a couple of projects may already take place prior to 2007. For example, a project has been proposed by Union Fenosa on the Sabon (Coruna) site where a 470-MW oil-fired plant could be repowered into a 800-MW combined cycle, fueled by a new LNG regasification facility. Over the 2007-2020 period, we estimate that potential at 1.5-3 GW. Less than 9% of that segment will be associated with turbines below 150 MW but another 35% of the GT capacity added may be associated with units between 150 MW and 200 MW. The bulk of that repowering power will be aiming at the Spanish baseload market.

IGCC. Potential IGCC applications in Spain could grow past 2015 and range between 1 and 2 GW through 2020. This implies 2-3 projects, all baseload and using turbines above 150 . MW.

Distributed Generation. We foresee few applications above the 30 MW level until 2010. Past then, we have forecast a potential range of 1-2 GW as we expect distribution companies and new retailers (which will emerge past 2004) to want to protect themselves against potential wholesale price variations. These applications will generate intermediate or peaking power and will be good targets for NGT use (all units likely to be in sizes below 150 MW).

Exhibit 4-1 - International KTM Market Prospects Summary

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	48	76	16%	32%	51%	*30*	*360*	*202*
Industrial Cogeneration	12	21	55%	39%	6%	*30*	*360*	*162*
Combined Heat and Power	3	7	26%	54%	20%	*30*	*200*	*105*
Repowering	8	17	78%	22%	0%	*100*	*360*	*228*
IGCC	5	10	93%	7%	0%	*150*	*360*	*254*
Distributed Generation	5	11	17%	46%	37%	*30*	*150*	*78*
TOTAL	**81**	**141**	**35%**	**32%**	**33%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Overall GT Capacity Share (%) <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	52	16.5	32.6	32%	63%	19%	38%
Industrial Cogeneration	11	6.4	8.7	58%	79%	7%	10%
Combined Heat and Power	3	3.1	3.5	89%	100%	4%	4%
Repowering	8	0.7	3.8	8%	48%	1%	5%
IGCC	5	0.0	1.6	0%	33%	0%	2%
Distributed Generation	6	6.2	6.2	100%	100%	7%	7%
TOTAL	**85**	**32.8**	**56.3**	**39%**	**66%**	**39%**	**66%**

	Per Duty Cycle (%)			GT Capacity (GW) below 150-200 MW		Country Share (%) of GT Capacity <150 -200 MW	
	Base	Intermediate	Peaking				
CC/SC Application				<150 MW	<200 MW	<150 MW	<200 MW
Brazil	26%	40%	35%	8.2	14.1	47%	81%
Mexico	44%	24%	32%	8.4	15.0	40%	72%
Germany	29%	41%	31%	4.9	7.9	34%	55%
Italy	38%	26%	36%	5.7	9.1	39%	61%
Spain	34%	34%	32%	5.6	10.3	32%	58%
TOTAL	**35%**	**32%**	**33%**	**32.8**	**56.3**	**39%**	**66%**

SOURCE: PA Consulting

Exhibit 4.2 -- Key Target Market Evolution

KTM	Brazil	Mexico	Germany	Italy	Spain
Current Deregulation Status					
-- Wholesale Power Market Status	In Place but iffy	Too early to tell	In Place	Being developed	In Place
-- Level of Market Liquidity	Too early to tell	Too early to tell	High	Increasing	Medium
-- Power Bidding Mechanisms	Daily, marginal cost dispatch	Daily, marginal cost dispatch	Block and hourly pricing	In discussion	Hourly pricing
-- Structure of Competition	Moving to unregulated gencos	Moving to unregulated gencos	Unregulated gencos	Moving to unregulated gencos	Unregulated gencos
Future Environmental Regulations	Favorable for gas	Favorable for gas	Neutral/ Favorable to gas	Favorable to gas	Favorable to gas
Future Gas Availability	Neutral	Neutral	Favorable	Neutral/ Favorable	Neutral
Future Energy Prices					
-- Electricity (wholesale)	$36-41/MWh	$25-30/MWh	$29-36/MWh	$33-40/MWh	$27-38/MWh
-- Natural Gas (for generators)	$2.5-3/ MMBtu	$2.5-3/ MMBtu	$2.2-3/MMBtu	$2.2-2.6/MMBtu	$2-2.5/MMBtu
Other External Factors	Regional	Political	Nuclear, Environmental	Environment, Supply diversity	Coal, Nuclear

SOURCE: PA Consulting

Exhibit 4.3 -- Summary International Baseline Period Projection (2001-2006)

KTM	Projected Demand Growth (%/yr)	Projected Capacity Additions (GW)		Implied Capacity Displacement (GW)
		Total	Gas-Fired CT/CC	
Brazil	3.5-4.5%	16-25	5-7	0
Mexico	4.5-5.5%	10-14.5	8.5-12.5	0
Germany	1-1.5%	13-16	4-8	9-12
Italy	3-3.5%	6-10	4-7.5	1-4
Spain	4-5%	10-12.5	6.5-8.5	1-1.5

SOURCE: PA Consulting

Exhibit 4.4 -- Summary International Competitive Phase Outlook (2007-2020)

KTM	Projected Demand Growth (%/yr)	Projected Capacity Additions (GW)	
		Total	Gas-Fired CT/CC
Brazil	3-5%	55-75	15-30
Mexico	3.5-5%	28-39	23-30
Germany	1-1.5%	20-35	10-22
Italy	2-3%	22-31	12-22
Spain	3-4%	24-37	16-27

SOURCE: PA Consulting

APPENDIX A: U.S. MARKET EVOLUTION

Appendix A -- U.S. Market Evolution

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In development; 50% mature	Competitive regional power markets in place, moving towards a national power market; activities managed by ISOs, Transcos and ISAs, following the lead of the four most active regions at present -- Cal ISO, New England and New York ISOs and PJM ISO
-- Level of Market Liquidity	Moderate-High	Probably close to 50% of power volume moving through spot market and power exchange sales; as of 2000, marketed volume was already close to the nation's electricity consumption but some regional markets are far more active than others
-- Power Bidding Mechanisms	Varying across regions	A total of 9-10 ISOs and 7-8 power exchanges will manage day-ahead, hour-ahead markets, ancillary services, real-time imbalance and congestion markets throughout the early 2000s. By 2005-2006, the number will get reduce to 6-7 coordinated ISO/PXs.
-- Structure of Competition	50% balanced; 50% Sticky	There are currently close to 90 active players. Through exits, divestitures, mergers, and secondary market transactions, between 20-25 large integrated convergent energy merchant companies will emerge by 2005, with actionable nationwide scope.
Environmental Regulations	Favorable to gas	With over 300 GW of existing coal-fired capacity facing growing environmental compliance costs over the next 5-10 years, gas is likely to be heavily favored in the near-term
Gas Availability	Favorable	Gas use is expected to increase substantially, as the marginal fuel for generation; however, supply is expected to be adequate as prices rise, and will be met through both domestic/Canadian sources
Energy Prices		
-- Electricity (wholesale)	$24-46/MWh	Wide range reflects differences across regions in terms of current generating mix and fuels likely to set the marginal generation price (e.g., coal and nuclear vs. oil and gas). Continued price volatilities for the next 4-5 years. Lower prices expected in 2002-2004. Past 2005, prices are likely to increase again. Past 2010, prices could further increase if coal plant retrofit requirements multiply.
-- Natural Gas (for generators)	$3.2-4.4/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Nuclear, Coal	Operating life and potential license extension of nuclear units an issue; nation has nearly 100 GW of nuclear capacity, 10-25 GW could be retired by 2020, but some units could be life extended; environmental compliance costs for coal capacity also an issue

Appendix A -- U.S. Market Evolution / Northeast/Mid-Atlantic (NPCC, MAAC)

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place	Competitive power market in place; as of today already one of the most active markets; activities will be managed by entities such as the PJM, New York, and New England ISOs or their successors
-- Level of Market Liquidity	High	100% of power volume moving through spot market and power exchange sales; as of 2000, marketed volume was already close to 100% of the region's electricity consumption
-- Power Bidding Mechanisms	Mature	Three ISOs or power exchanges are in place, one in each region (including NY). Under pressure to harmonize rules patterned after the MAAC/PJM approach which has worked well so far. Systems will thus merge and a single exchange could be in place by 2003 to manage day-ahead and hour-ahead markets, ancillary services, real-time imbalance and congestion markets. PJM is also expected to introduce demand-side bidding in 2002-03.
-- Structure of Competition	Very Balanced	So far, many players as the result of divestitures in several states which allowed new entrants to secure capacity. Very few incumbents with substantial assets. A period of asset consolidation can be expected in 2002-2004 as the result of secondary market transactions and asset portfolio swaps. Eventually about 7-10 large players will emerge.
Environmental Regulations	Favorable to gas	Region favorably disposed to gas-fired generation
Gas Availability	Neutral	Increased supplies (e.g., Sable Island) expected from Canadian and Midwestern pipeline projects
Energy Prices		
-- Electricity (wholesale)	$31-43/MWh	So far, volatility in the Northeast has been somewhat limited and price correlations with other regions have been limited. Northeast is a very competitive market with many players; NY has also a large number of participants but still a bit less competitive because of congestions and potential lack of capacity in some pockets but NY prices correlate fairly well with NEPOOL's; MAAC has some volatility (higher prices in the east because of west-east transmission constraints. Overall, generation prices expected to remain relatively stable. Prices will drop faster in New England to the $31-33/MWh range than in New York where they could stay around $35-38/MWh. However, New England may recoup and become higher by 2006. MAAC prices will be more in between the two others in a $33-37 price band.
-- Natural Gas (for generators)	$3.5-4.4/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Nuclear	Operating life and potential license extension of nuclear units an issue; region has 22 GW of nuclear capacity (about 25% of the U.S. total)

Appendix A -- U.S. Market Evolution / Midwest (ECAR, MAIN, MAPP)

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place	Competitive power market in place, managed by entities such as the Midwest ISO, the MAPP RTO and the Alliance Transco or their successors
-- Level of Market Liquidity	Medium-High	Probably close to 80% of power volume moving through spot market and power exchange sales; as of 2000, marketed volume was about 40% of the region's electricity consumption
-- Power Bidding Mechanisms	In implementation	Most utilities in MAIN and the ECAR western region belong to Midwest ISO (which is not very empowered compared to CA or PJM); eastern ECAR utilities belong to the Alliance RTO. Strong hubs in ComEd, Cinergy and around First Energy. Generally, dominance of bilateral contracts for capacity and energy. Coordinated ISO may be by 2005.
-- Structure of Competition	Balanced	Some large incumbents (Com Ed, Cinergy, First Energy) and hub managers in place. Market will take another 4-5 years to stabilize and see the emergence of 8-12 large players. More divestitures can be expected and 3-4 large mergers as well.
Environmental Regulations	Favorable to gas near-term	With nearly 130 GW of coal-fired capacity, the Midwest has the most coal-fired capacity nationally (43% of the U.S. total) and the highest fraction of coal in its generating base of any region (nearly 70%); environmental regulations and the cost of compliance likely to favor gas
Gas Availability	Favorable	Midwest emerging as major regional supply and trading hub
Energy Prices		
-- Electricity (wholesale)	$24-34/MWh	High price volatility and prices likely to prevail through 2003. Formation of RTOS should solidify price patterns and low prices could prevail in 2004-05. Thereafter, progressive price increases (i.e., 0.5%-1%/year in constant dollars) will emerge but marginal prices will continue to be set by coal-fired capacity for several years except for some limited peak periods.
-- Natural Gas (for generators)	$3.2-4.1/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Nuclear/Coal	Region's capacity is 80% nuclear (24 GW) and coal (130 GW) and it has the most of both forms of capacity of any region; operating life and potential license extension of nuclear units an issue (region has 25% of the U.S. nuclear total); environmental compliance costs for coal capacity also an issue

Appendix A -- U.S. Market Evolution / Southeast (SERC w/FRCC, SPP)

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	Developing/ In Place	Competitive power market now developing and likely to be in place by 2004-05; however, currently furthest behind in terms of competitive market development; activities likely to be managed by 2 RTOs (alternate proposals under consideration)
-- Level of Market Liquidity	Increasing	Increasing amount of power volume will move through spot market and power exchange sales; however, as of 2000, marketed volume was one of the lowest nationally at only about 25-30% of the region's electricity consumption
-- Power Bidding Mechanisms	Immature	No formal proposal for any ISO or power exchange in consideration. Very balkanized regions as indicated by the 4 competitive RTO proposals that competed throughout most of 200. Will need to wait until 2003-2004. It will then take another 1-2 years for the market to settle (will also depend on the extent of divestitures required by state regulators). Market will thus continue to rely on bilateral contracts for capacity and energy.
-- Structure of Competition	Balkanized	So far, market dominated by strong incumbents such as Southern, Duke, Florida utilities. Partial divestitures possible in 2002-2004. Several mergers have occurred in the past and another 2-3 could take place in 2001-2002. Some 6-8 large players could eventually emerge. Role of TVA important. SPP market very incumbent-driven (least developed competitive market)
Environmental Regulations	Favorable to gas near-term	With over 100 GW of coal-fired capacity, the Southeast has the second most coal-fired capacity nationally (33% of the total); environmental regulations and the cost of compliance likely to favor gas in the near-term
Gas Availability	Neutral/ Favorable	New pipeline projects need to be implemented to ensure gas availability, but region is favorable located to Gulf Coast and Texas supplies
Energy Prices		
-- Electricity (wholesale)	$25-39/MWh	Generation prices have the potential to become quite volatile and Florida prices may continue to be 15-20% above the region average. Higher volatility to be expected between 2003 and 2006 as the market starts to truly deregulates and capacity additions start to come on line.
-- Natural Gas (for generators)	$3.2-4.2/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Nuclear, Coal	Operating life and potential license extension of nuclear units an issue; region has 37 GW of nuclear capacity, most in the nation (38% of the U.S. total); environmental compliance costs for coal capacity also an issue

Appendix A -- U.S. Market Evolution / Southwest (ERCOT)

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place	Competitive power market in place, managed by the Texas ISO or its successors. Market not synchronized with Eastern or Western interconnects.
-- Level of Market Liquidity	Increasing	Increasing with more and more power volume moving through spot market and power exchange sales; as of 2000, marketed volume was about 20% of the region's electricity consumption
-- Power Bidding Mechanisms	Maturing	ISO in place but no active power exchange. Region still relies on bilateral contracts for capacity and energy. Power exchange may be possible by 2003-2004.
-- Structure of Competition	Balanced	Little divestiture activity to date. Only partial divestitures being considered. Some strong incumbents but deregulation bill imposes some constraints on market shares (generally not over 20%). Between 5 and 6 large players to emerge. Strong merchant capacity under development.
Environmental Regulations	Favorable to gas	Region favorably disposed to gas-fired generation
Gas Availability	Favorable	Major gas producing and supply region
Energy Prices		
-- Electricity (wholesale)	$26-35/MWh	Generation prices expected to drop to $26/MWh on average in 2002 and $28/MWh in 2003 to then progressively increase to $33-35/MWh by 2005-2006. Some increase in price volatility may be expected past 2004.
-- Natural Gas (for generators)	$3.0-4/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Regional	Key need is for greater interconnection with surrounding regions

Appendix A -- U.S. Market Evolution / West (WSCC)

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	Restructuring	Competitive power market shut down. A new entity may reappear in 2-4 years. Meanwhile, the California ISO, the NorthWest RTO and the Mountain West ISA will be in charge.
-- Level of Market Liquidity	Challenged	A new market environment will need to be defined in California.
-- Power Bidding Mechanisms	Needs restructuring	A complete overhaul will need to take place in California. Another ISO can develop by 2002-3 outside of CA. Then, up to 3 RTOS (includes ISO-West in Pacific Northwest and Desert-STAR) may be in place by 2003-4.
-- Structure of Competition	Sticky	In California, market was dominated by 8-10 merchants. Outside CA, the market involves a lot more players, including quite a few munis, coops and Federal power entities. By 2005, some 8-10 large unregulated players may be able to start dominating across the entire region, with a good control over possible arbitrage opportunities between CA and the rest of the region.
Environmental Regulations	Favorable to gas near-term	With over 30 GW of coal-fired capacity, WSCC has the third most coal-fired capacity nationally, even though coal only represents 22% of the region's total generating capacity; environmental regulations and the cost of compliance likely to favor gas in the near-term
Gas Availability	Unfavorable/ Neutral	Additional supply capability needed towards California
Energy Prices		
-- Electricity (wholesale)	$32-46/MWh	Generation prices to drop to the low 30s in 2002-03 but prices could then rise again to the low 40s by 2005 and mid-40s within the 2006-2007 period. By then, anticipated coal retrofit requirements could cause further price inflation.
-- Natural Gas (for generators)	$3.6-4.4/ MMBtu	General view now is for prices to drop to their lows in 2002 and 2003 and then modestly increase through 2006
Other External Factors	Nuclear, Coal	Operating life and potential license extension of nuclear units an issue; region has 9 GW of nuclear capacity; environmental compliance costs for coal capacity also an issue

APPENDIX B: U.S. BASELINE PERIOD PROJECTIONS

Appendix B -- U.S. Baseline Period Outlook (2001-2006)

U.S. TOTAL		
Projected Demand Growth (%/yr)	1.7-2.2%	Recent growth has been at the high end of the range
Projected Capacity Additions (GW)		
-- Total Additions	139-175	About 6-13% of additions could be to offset retirements (10-19 GW) or economic displacement (3-6 GW) of existing units with balance of range to reflect load growth differences
-- Gas-Fired CT/CC Additions	133-167	Overall, more oriented towards CC units (about 68% of total), tied to rapid near-term growth in merchant, wholesale-market oriented generation; could include 1.5-3 GW of gas repowering
Implied Capacity Displacement (GW)	13-25	Most displacement activity focused in NPCC, SERC, ECAR and ERCOT regions, with new units aiming to replace older oil- and gas-fired steam or CT units

Appendix B -- U.S. Baseline Period Outlook (2001-2006)

ECAR		
Projected Demand Growth (%/yr)	1.6-2.0%	Growth likely to be towards 1.7-1.8%
Projected Capacity Additions (GW)		
-- Total Additions	15-20	
-- Gas-Fired CT/CC Additions	14-19	CT peaking capacity requirements grew up to 45% of likely additions; additions also likely to include 1-1.5 GW of cogeneration.
Implied Capacity Displacement (GW)	2.5-4	Includes 2.5 GW of announced/programmed retirements

ERCOT		
Projected Demand Growth (%/yr)	1.9-2.3%	One of strongest growing regions; based on recent trends, growth likely to be around 2.1%/year range
Projected Capacity Additions (GW)		
-- Total Additions	11.5-13	Includes about 0.75-1 GW of additional renewable capacity
-- Gas-Fired CT/CC Additions	10.5-12	Requirements include peaking, intermediate and baseload capacity, including 1.25 GW of new cogeneration. About 85% of additions are CCs; less than 15% for CTs (almost all utility-owned).
Implied Capacity Displacement (GW)	3-4	Includes 3 GW of announced/programmed retirements

MAAC		
Projected Demand Growth (%/yr)	1.6-2.1%	Growth likely to be around 1.8%
Projected Capacity Additions (GW)		
-- Total Additions	9-12.5	Relatively wide range of potential additions (some estimates over 15 GW) depending on load growth, extent of economic displacements in 2005-2006.
-- Gas-Fired CT/CC Additions	8.5-12	About 25% CTs and 75% CC units; less than 1 GW of cogeneration
Implied Capacity Displacement (GW)	1-2	Displacement of older QFs and fossil-fired baseload; less than 1 GW of planned/announced retirements

Appendix B -- U.S. Baseline Period Outlook (2001-2006)

MAIN		
Projected Demand Growth (%/yr)	1.5-1.9%	Growth likely to be around 1.7% per year
Projected Capacity Additions (GW)		
-- Total Additions	10.5-15	About 17 GW of merchant projects announced to date (includes 0.5-1 GW of cogeneration)
-- Gas-Fired CT/CC Additions	10-14.5	About 65% CC
Implied Capacity Displacement (GW)	1-2	Coal capacity will not be in play before 2007

MAPP		
Projected Demand Growth (%/yr)	1.4-1.75%	Growth now likely to be at 1.6% per year
Projected Capacity Additions (GW)		
-- Total Additions	2.5-3.5	Little new renewable capacity included (<0.35 GW over period)
-- Gas-Fired CT/CC Additions	2.1-3.25	CT requirements around 45-50%
Implied Capacity Displacement (GW)	0.2-0.75	Only 0.2 GW of planned/announced retirements

NPCC		
Projected Demand Growth (%/yr)	1.3-1.7%	
Projected Capacity Additions (GW)		
-- Total Additions	12-15	High end of estimate assumes high growth of 1.7% and includes up to 0.3 GW of renewables.
-- Gas-Fired CT/CC Additions	11.5-14.5	Over 80% likely to involve CC units for competitive, wholesale generation; about 20% of the additions could involve repowering.
Implied Capacity Displacement (GW)	2-4	Over 4 GW of retirements have been announced

Appendix B -- U.S. Baseline Period Outlook (2001-2006)

SERC (including FRCC)		
Projected Demand Growth (%/yr)	1.9-2.4%	Growth likely to be over 2.2%
Projected Capacity Additions (GW)		
-- Total Additions	40-49	Could include 3-4 GW of cogeneration (7.7 GW announced, the highest of all regions)
-- Gas-Fired CT/CC Additions	39.5-48	Fairly balanced need for peaking and intermediate/baseload capacity; CC additions could represent about 55% of total gas-fired additions.
Implied Capacity Displacement (GW)	3-4	Limited expectations during the first period (more past 2007)

SPP		
Projected Demand Growth (%/yr)	1.5-2.0%	Near-term growth likely to be at 1.75%/year
Projected Capacity Additions (GW)		
-- Total Additions	7-10	Some uncertainty over potential demand growth and possible requirements to offset up to 3 GW of potential retirements; 1 GW of cogeneration also announced
-- Gas-Fired CT/CC Additions	7-10	More CTs; CC units could account for 60% of additions if retirements occur
Implied Capacity Displacement (GW)	0-2	On the high end, about 1.5 GW of CTs and 0.5 GW of fossil-fired steam capacity.

WSCC		
Projected Demand Growth (%/yr)	2.1-2.6%	Near-term growth now likely to be around 2.3%
Projected Capacity Additions (GW)		
-- Total Additions	31.5-37	High end assumes strong demand growth and up to 2 GW of renewables
-- Gas-Fired CT/CC Additions	30-34	Most requirements for baseload/intermediate CC units, which could account for 85% of total gas-fired additions
Implied Capacity Displacement (GW)	0.5-2	Outside of California

APPENDIX C: U.S. COMPETTIVE PHASE OUTLOOK

Appendix C -- U.S. NGT Competitive Phase Outlook (2007-2020)

U.S. TOTAL		
Projected Demand Growth (%/yr)	1.6-2.0%	Median growth outlook at 1.8%/year range
Projected Capacity Additions (GW)		
-- Total Additions	260-378	Range reflects uncertainty over demand growth, extent of baseline period additions, future retirements, potential nuclear plant life extensions, environmental compliance issues for coal capacity and future economic displacement
-- Gas-Fired CT/CC Additions	215-322	Longer-term more balanced mix of CT and CC units likely, perhaps 50/50, to meet needs for both peaking and intermediate/baseload capacity
Implied Capacity Displacement (GW)	86-160	Mostly Midwest, Northeast and Southeast.

Appendix C -- U.S. NGT Competitive Phase Outlook (2007-2020)

Northeast/Mid-Atlantic (NPCC, MAAC)		
Projected Demand Growth (%/yr)	1.3-1.7%	Lower than the national average
Projected Capacity Additions (GW) -- Total Additions	24-43	Early retirement of nuclear units would add to regional requirements
-- Gas-Fired CT/CC Additions	21-39	Difference with total additions involving cogeneration and renewables
Possible Capacity Displacement Upside (GW)	20-35	Mostly peaking and intermediate oil-fired capacity

Midwest (ECAR, MAIN, MAPP)		
Projected Demand Growth (%/yr)	1.4-1.8%	About the same as the national average
Projected Capacity Additions (GW) -- Total Additions	45-81	Outlook for total additions, and for gas-fired units, depends on future use of coal-fired units
-- Gas-Fired CT/CC Additions	35-68	Difference with total additions involving coal-fired capacity
Possible Capacity Displacement Upside (GW)	25-49	Older baseload and cycling coal-fired capacity

Southeast (SERC w/FRCC, SPP)		
Projected Demand Growth (%/yr)	1.7-2.1%	Slightly higher than the national average
Projected Capacity Additions (GW) -- Total Additions	94-126	Outlook for total additions, and for gas-fired units, depends on future use of coal-fired units and potential life extension of nuclear capacity
-- Gas-Fired CT/CC Additions	85-113	Difference involving cogeneration and coal-fired capacity
Possible Capacity Displacement Upside (GW)	15-35	Oil-fired cycling capacity

Appendix C -- U.S. NGT Competitive Phase Outlook (2007-2020)

Southwest (ERCOT)		
Projected Demand Growth (%/yr)	1.6-2.0%	Somewhat higher than the national average
Projected Capacity Additions (GW)		
-- Total Additions	22-33	Key uncertainty is demand growth; existing capacity is not heavily oriented towards coal (25%) or nuclear (8%) capacity; therefore, it will be less affected than some regions by environmental issues
-- Gas-Fired CT/CC Additions	18-28	Difference involving renewables, cogeneration and coal-fired capacity
Possible Capacity Displacement Upside (GW)	10-17	Fossil-fired intermediate mid-size plants

West (WSCC)		
Projected Demand Growth (%/yr)	1.7-2.3%	Higher than the national average
Projected Capacity Additions (GW)		
-- Total Additions	73-95	Would include between 5 and 9 GW of potential coal-based additions plus 1-2.5 GW of new renewables. Extent of economic displacement could reach 5-10 GW.
-- Gas-Fired CT/CC Additions	56-74	Difference with total additions involving renewables, cogeneration and coal-fired capacity (outside CA)
Possible Capacity Displacement Upside (GW)	16-24	CA-based capacity being repowered

Appendix C - U.S. Market Prospects - Northeast/Mid-Atlantic (NPCC, MAC) Region

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	11.2	21.2	19%	63%	19%	*30*	*360*	*235*
Industrial Cogeneration	1.6	2.8	36%	55%	9%	*30*	*360*	*199*
Combined Heat and Power	1.2	2	13%	50%	38%	*30*	*150*	*86*
Repowering	4.6	8	71%	29%	0%	*100*	*360*	*210*
IGCC	0	0	--	--	--	--	--	--
Distributed Generation	2.4	5	0%	41%	59%	*30*	*150*	*80*
TOTAL	**21**	**39**	**28%**	**52%**	**20%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	12	2.2	5.2	19%	45%	10%	24%
Industrial Cogeneration	2	0.4	1.0	25%	65%	2%	5%
Combined Heat and Power	1	1.3	1.3	100%	100%	6%	6%
Repowering	4	0.6	2.6	15%	63%	3%	12%
IGCC	0	0.0	0.0	0%	0%	0%	0%
Distributed Generation	3	3.2	3.2	100%	100%	15%	15%
TOTAL	**22**	**7.6**	**13.2**	**35%**	**61%**	**35%**	**61%**

Source: PA Consulting

Appendix C - U.S. Market Prospects -- Midwest (ECAR, MAIN, MAPP) Region

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	20.1	40.2	17%	32%	51%	*30*	*360*	*227*
Industrial Cogeneration	4	7.6	78%	22%	0%	*30*	*360*	*189*
Combined Heat and Power	1.5	2.6	24%	51%	24%	*30*	*150*	*83*
Repowering	5.8	10.1	50%	50%	0%	*100*	*360*	*256*
IGCC	0	0	--	--	--	--	--	--
Distributed Generation	3.6	7.5	10%	36%	54%	*30*	*150*	*85*
TOTAL	**35**	**68**	**28%**	**35%**	**37%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	25	6.3	11.3	25%	45%	16%	28%
Industrial Cogeneration	4	1.6	2.5	43%	67%	4%	6%
Combined Heat and Power	2	1.5	1.5	100%	100%	4%	4%
Repowering	5	0.0	2.0	0%	39%	0%	5%
IGCC	0	0.0	0.0	0%	0%	0%	0%
Distributed Generation	5	4.7	4.7	100%	100%	12%	12%
TOTAL	**40**	**14.1**	**22.0**	**35%**	**55%**	**35%**	**55%**

Source: PA Consulting

Appendix C - US. Market Prospects (2007-2020) - Southeast (SERC w/FRCC, SPP) Region

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	69.7	85.5	24%	37%	38%	*30*	*360*	*226*
Industrial Cogeneration	8	14	64%	36%	0%	*30*	*360*	*205*
Combined Heat and Power	1.5	2.5	30%	60%	10%	*30*	*150*	*82*
Repowering	3.4	6	85%	15%	0%	*100*	*360*	*275*
IGCC	3	5	100%	0%	0%	*150*	*360*	*292*
Distributed Generation	2.4	5	19%	27%	54%	*30*	*150*	*84*
TOTAL	**88**	**118**	**34%**	**35%**	**31%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	61	14.4	30.4	24%	50%	18%	39%
Industrial Cogeneration	7	2.6	4.3	36%	60%	3%	6%
Combined Heat and Power	1	1.4	1.4	100%	100%	2%	2%
Repowering	3	0.0	1.0	0%	32%	0%	1%
IGCC	3	0.0	0.4	0%	15%	0%	0%
Distributed Generation	3	3.1	3.1	100%	100%	4%	4%
TOTAL	**78**	**21.5**	**40.5**	**28%**	**52%**	**28%**	**52%**

SOURCE: PA Consulting

Appendix C - US. Market Propects (2007-2020) - Southwest (ERCOT) Region

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	11.4	15.7	28%	31%	41%	*30*	*360*	*212*
Industrial Cogeneration	2.4	4.6	71%	29%	0%	*30*	*360*	*210*
Combined Heat and Power	0.6	0.9	27%	67%	7%	*30*	*150*	*93*
Repowering	2.4	4.3	60%	40%	0%	*100*	*360*	*273*
IGCC	0	0	--	--	--	--	--	--
Distributed Generation	1.2	2.5	11%	65%	24%	*30*	*150*	*98*
TOTAL	**18**	**28**	**38%**	**36%**	**26%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	11	3.4	6.1	32%	57%	20%	36%
Industrial Cogeneration	2	0.8	1.4	35%	61%	5%	8%
Combined Heat and Power	1	0.5	0.5	100%	100%	3%	3%
Repowering	2	0.0	0.7	0%	31%	0%	4%
IGCC	0	0.0	0.0	0%	0%	0%	0%
Distributed Generation	1	1.4	1.4	100%	100%	8%	8%
TOTAL	**17**	**6.1**	**10.1**	**36%**	**59%**	**36%**	**59%**

SOURCE: PA Consulting

Appendix C - US. Market Prospects (2007-2020) - West (WSSC) Region

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	44.6	53.4	20%	32%	48%	*30*	*360*	*224*
Industrial Cogeneration	4	7	73%	27%	0%	*30*	*360*	*192*
Combined Heat and Power	1.2	2	19%	38%	44%	*30*	*150*	*78*
Repowering	3.8	6.6	58%	42%	0%	*100*	*360*	*243*
IGCC	5	8	92%	8%	0%	*150*	*360*	*268*
Distributed Generation	2.4	5	19%	27%	54%	*30*	*150*	*82*
TOTAL	**61**	**82**	**34%**	**30%**	**37%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150, 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	40	8.7	19.8	22%	49%	16%	36%
Industrial Cogeneration	4	1.4	2.4	40%	68%	3%	4%
Combined Heat and Power	1	1.3	1.3	100%	100%	2%	2%
Repowering	3	0.3	1.2	8%	35%	0%	2%
IGCC	4	0.0	0.6	0%	15%	0%	1%
Distributed Generation	3	3.1	3.1	100%	100%	6%	6%
TOTAL	**56**	**14.8**	**28.5**	**27%**	**51%**	**27%**	**51%**

SOURCE: PA Consulting

APPENDIX D: INTERNATIONAL MARKET EVOLUTION

Appendix D -- International Market Evolution / Brazil

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place but iffy	Transition to competitive market very affected by ongoing power crisis; market rules being changed and criticized. Potential progressive opening (in 25% increments) to start in 2003-2004.
-- Level of Market Liquidity	Too early to tell	Right now, no liquidity. Liquidity will increase progessively over time with new entrants and more marketers and as market moves from transition contracts set under Valor Normativo (VN) (reference prices), initially 10-15% of total volume through spot sales
-- Power Bidding Mechanisms	Daily, marginal cost dispatch	Not yet determined, likely to follow other wholesale/pool-type markets with 1 day ahead supply bidding, marginal cost dispatch pricing and short-term marginal cost spot pricing; market likely to see a transitional phase starting in 2006/07 to ease to fully competitive pricing after expiration of VN-based transition contracts
-- Structure of Competition	Moving to unregulated gencos	IPPs and privatized gencos will compete for new generation capacity; power sales competition to involve generators, including some larger industrial generators, along with power marketers
Environmental Regulations	Favorable for gas	None to limit CT/CC technology; natural gas preferred fuel for future capacity additions, in part to introduce fuel diversity into hydro-based systems, but also in some areas to alleviate air pollution
Gas Availability	Neutral	Need to continue to invest in gas pipelines to be able to support desired gas-fired capacity expansion; need includes develop of domestic supplies and development of regional imports
Energy Prices		
-- Electricity (wholesale)	\$36-41/MWh	Likely to stay in line with current levels, with appropriate fuel, inflation or currency adjustments; future reference gas-fired/CC marginal costs placed at \$45/MWh in 2005 and \$60/MWh in 2020; competitive VN price set at \$32.40/MWh in 1999 and recent IPP bids have been in the \$35-37/MWh range; price volatility expected given large base of hydroelectric capacity
-- Natural Gas (for generators)	\$2.5-3/ MMBtu	Petrobras has been charging about \$2.5-2.7/MMBtu for gas from the Bolivia-to-Brazil pipeline; thanks to a new law aimed at spurring development, IPPs now benefit from some protection against currency price fluctuations.
Other External Factors	Regional	Brazil is the largest energy market in South America; however, ability to expand power sector and the shape of the expansion will be tied to regional resources and development -- e.g., extent of power imports from Argentina and Venezuela, ability to develop and import gas from Argentina and Bolivia

Appendix D -- International Market Evolution / Mexico

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	Too early to tell	A competitive wholesale market first proposed in 1999 by Pres. Zedillo. Status uncertain under new Pres. Fox; possible by 2007 but could be around 2009-2011
-- Level of Market Liquidity	Too early to tell	Will increase progressively over time with new entrants; initially low with most sales through bilateral contracts between generators and distribution companies and/or end-users
-- Power Bidding Mechanisms	Daily, marginal cost dispatch	Likely to follow current proposed structure; generators bid supply 1 day ahead, priced at Last Accepted Offer (LAO) (most expensive generator dispatched) with no transmission constraints; with constraints locational pricing with overall system least cost dispatch; when reserve margin is low LAO price may be increased with a cost of failure adjustment; Secretary of Energy may also introduce "K Factor" capacity payments to promote new construction
-- Structure of Competition	Moving to unregulated gencos	IPPs and privatized CFE gencos will compete for new generation capacity; power sales competition to involve generators, including some larger industrial generators, along with power marketers
Environmental Regulations	Favorable for gas	None to limit CT/CC technology; natural gas preferred fuel for future capacity additions, in part to help alleviate key environmental concerns of air pollution in Mexico City and along the industrialized U.S./Mexican border
Gas Availability	Neutral	May be an issue; need to continue/expand investment in gas infrastructure to develop domestic sources and/or to increase U.S. gas imports
Energy Prices		
-- Electricity (wholesale)	$25-30/MWh	Likely to track from current levels with fuel, inflation and currency adjustments; retail rates currently around 5-6 c/kWh; wholesale supply rates on bids to CFE about 2.5-3 c/kWh
-- Natural Gas (for generators)	$2.5-3/ MMBtu	Expect prices in constant dollars in the $2.5-3/MMBtu range; historically gas prices have been quite comparable to U.S. prices
Other External Factors	Political	Strong internal demand for power and desire for CT/CC-type additions; CFE's role and internal politics likely to be key determinant over deregulation timing and creation of a competitive market

Appendix D -- International Market Evolution / Germany

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place	Market liberalization started in 1998 and two power exchanges in operation for over a year; exchange merger possile soon leading the way to a integrated market place by 2004-2005
-- Level of Market Liquidity	High	High level of liquidity (coupled with volatility); two power exchanges (Leipzig and Frankfurt) started operating in 2000
-- Power Bidding Mechanisms	Hourly pricing	Full set of offerings (day ahead, hourly blocks, intra-day and futures).
-- Structure of Competition	Unregulated gencos	Existing IOUs, regional utilities and international IPPs will compete for new generation; power sales to involve power marketers (many affiliated with these same generating companies)
Environmental Regulations	Neutral/ Favorable to gas	Likely to favor gas-fired technology, but add costs to all forms of generation; potential extension of current ecology tax -- 1.2 c/kWh tax on electricity, gas, coal and oil, with another 1.2 c/kWh to be added in 2003 (high-efficiency, gas-fired cogeneration currently exempt)
Gas Availability	Favorable	Gas access should not be an issue, country centrally located within Europe and has many domestic and import supply options
Energy Prices		
-- Electricity (wholesale)	$29-36/MWh	Wholesale prices have dropped and may continue to drop to $27/MMWh in 2003-3004, then increase back up to reach $29/MWh in 2007. Intermediate prices will decrease to the $25-28/MWh range and peaking prices will move in the $35-43/MWh range. Longer-term prices could increase by 1-2%/year, following fuel and other general operating cost increases
-- Natural Gas (for generators)	$2.2-3/MMBtu	Decreasing marginally from today's $3+/MMBtu to $2.3-2.4 in 2003/05 as regional supply increases; then reaching $2.5/MMBtu in 2006 and $2.8/MMBtu in 2010. Longer-term prices likely to increase as regional gas demand increases (largely driven by increased requirements for power generation)
Other External Factors	Nuclear, Environmental	Overall level of capacity requirements and associated energy mix will be heavily influenced by timing of nuclear plant closures, extent of environmentally-related energy taxation and level of renewable additions.

Appendix D -- International Market Evolution / Italy

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	Being developed	Independent grid management company formed in 2000, power pool to start in 2002
-- Level of Market Liquidity	Increasing	Liquidity should increase, initial wholesale market to start in 2002/03
-- Power Bidding Mechanisms	Hourly pricing	Hourly merit based dispatch; contracts include spot market and bilateral contracts with distribution companies, retailers and end-users
-- Structure of Competition	Moving to unregulated gencos	Incumbent utility (ENEL) will still be largest generator, but market share will be less than 50%, competition to include independent generators (including gencos spun-off from ENEL), large industrial generators and power marketers; 3 gencos spun-off from ENEL in 1999 could be privatized by 2001/03
Environmental Regulations	Favorable to gas	Environmental taxes and regulations favoring gas use
Gas Availability	Neutral/ Favorable	Gas oversupply situation through 2005, longer-term availability should be in balance with deficits met through imports
Energy Prices		
-- Electricity (wholesale)	\$33-40/MWh	Wholesale prices are expected to drop to \$33/MWh in 2002, then around \$30/MWh in 2003-2004 to then stabilize around \$33/MWh in 2007. Intermediate prices will decrease a bit (\$30-35/MWh) but peaking prices will show increasing volatility (\$36-45/MWh). Longer-term prices could trend upward with price increases likely to be in the 1-2%/year range, reflecting fuel and other general operating cost increases
-- Natural Gas (for generators)	\$2.2-2.6/MMBtu	After recent price increases, should decrease through 2005/07 as regional supply increases; longer-term prices likely to increase as regional gas demand increases (largely driven by increased requirements for power generation)
Other External Factors	Environment, Supply diversity	Key issues are need to meet environmental objectives, aim is to increase gas and renewable energy use; over 50% of gas (or LNG) is imported from Algeria or Russia, diversification of supply is seen as an important issue (options include Libya, Norway and Nigeria); Italy has 4 nuclear plants which have been idle since 1987, nuclear energy use not expected over the outlook period

Appendix D -- International Market Evolution / Spain

Extent of Deregulation/Privatization		
-- Wholesale Power Market Status	In Place	Full liberalization of power market expected by 2005; government pushing for faster opening
-- Level of Market Liquidity	Medium	Mandatory wholesale pool began in 1998; volatility and exchange patterns to increase when market fully open
-- Power Bidding Mechanisms	Hourly pricing	Hourly merit based dispatch; contracts include spot market and bilateral contracts with distribution companies, retailers and end-users
-- Structure of Competition	Unregulated gencos	Competition to include local IOUs (four strong incumbents) and independent power companies
Environmental Regulations	Favorable to gas	Programs and policies are generally aiming to boost domestic gas use; however, Spain has also been trying to protect domestic coal industry and has opposed EU plans to tax coal
Gas Availability	Neutral	Demand for gas in power production will increase at a rate of 10% per year; demand to be met by imports
Energy Prices		
-- Electricity (wholesale)	$27-38/MWh	With oversupply and increased competition, prices are expected to drop from $34/MWh to $29/MWh in 2002 then hover around $25/MWh in 2003-2004. Prices will then increase back up to $27 in 2007. Intermediate prices will decrease in the early 2010s (staying around $27-30/MWh) while peaking prices will rise in the $33-40/Mwh range. Long-term prices will also increase by 1-2% per year reflecting fuel and operating costs
-- Natural Gas (for generators)	$2-2.5/MMBtu	Decreasing marginally from today's $2.7-3/MMBtu to $2.3/MMBtu through 2005/10 as regional supply increases; longer-term prices (past 2008/2010) likely to increase as regional gas demand increases (largely driven by increased requirements for power generation)
Other External Factors	Coal, Nuclear	Coal is Spain's main indigenous resource; however, it is too expensive to compete in a deregulated energy market and has been subsidized; the extent of future susibidies will influence its use; retirement of existing nuclear capacity (7.4 GW) has not been as visibily discussed as in Germany, but it is likely that nuclear use will continue to decrease throughout the competitive phase and plant licenses expire

APPENDIX E: INTERNATIONAL MARKET BASELINE PERIOD PROJECTIONS

Appendix E -- International Market Baseline Period Projection (2001-2006)

BRAZIL		
Projected Demand Growth (%/yr)	3.5-4.5%	Forecasts range from 3.5%/yr to 6%/yr, tied to expectations of overall economic growth (concerns about potential crisis)
Projected Capacity Additions (GW)		
-- Total Additions	16-25	Previous official 10-yr plan of 45 GW (up from 36 GW in 1998) called for 22 GW of 2001-2006. Now new emergency plan with a goal of 20 GW for 2001-2004 (8 GW for hydro; 6.5 GW for thermal and 2 GW miscellaneous).
-- Gas-Fired CT/CC Additions	5-7	Based on new plan calling for 6.5 GW of gas-fired additions through 2004 but IPP activity can be expected to be delayed as the result of investors' lack of confidence in the new market rules
Implied Capacity Displacement (GW)	0	No economic displacement likely given needed for new capacity to offset potential shortages

MEXICO		
Projected Demand Growth (%/yr)	4.5-5.5%	Official forecast is 6%/yr through 2007 but recent growth 4-5%/yr and economic slowdown under way
Projected Capacity Additions (GW)		
-- Total Additions	10-14.5	Official forecast is for 17.5 GW, however actual additions can be expected to be lower based on lower and uneven load growth and inability to bid, finance and construct all projected additions
-- Gas-Fired CT/CC Additions	8.5-12.5	Official forecast is for 15.8 GW; actual additions will probably be lower; most plants will be structured as BLT plants selling output to CFE; predominant configuration is phased combined cycle plants totaling 450-900 MW
Implied Capacity Displacement (GW)	0	No economic displacement likely given needed for new capacity to offset potential shortages; some oil-to-gas conversions possible

Appendix E -- International Market Baseline Period Projection (2001-2006)

GERMANY		
Projected Demand Growth (%/yr)	1-1.5%	Demand growth currently very modest plus economic slowdown
Projected Capacity Additions (GW)		
-- Total Additions	13-16	Currently a capacity surplus and low demand growth; most additions for replacing aging capacity (particularly in the former East Germany) - some replacements for environmental reasons
-- Gas-Fired CT/CC Additions	4-8	Potentially including 3-4 GW of merchant, independent power capacity but current efforts to develop merchant plants have been unsuccessful as the result of a drop in wholesale prices; could start again around 2003-2004
Implied Capacity Displacement (GW)	9-12	Most capacity additions to offset aging/retired capacity; some merchant additions could be aimed at displacing or competing with existing capacity

ITALY		
Projected Demand Growth (%/yr)	3-3.5%	Demand growth increased 7.5%/year from 1995 to 1998 but has slowed since
Projected Capacity Additions (GW)		
-- Total Additions	6-10	Differing views exist on near-term outlook; some see oversupply to exist until 2010 and perhaps beyond, others see possible need up to 10 GW over the next 10 years and potential shortfalls (up to 3-4 GW) by 2002/03; divergent views partly tied to reserve margin situation -- nameplate is over 40% but operating margin often just over 10%
-- Gas-Fired CT/CC Additions	4-7.5	Modest requirements for new capacity, major activity could involve oil-to-gas conversions; ENEL has recently planned 22 GW of such conversions over the next 10+ years
Implied Capacity Displacement (GW)	1-4	Potentially 6 GW of merchant independent power additions over the next 5-6 years

SPAIN		
Projected Demand Growth (%/yr)	4-5%	Slowing from recent growth rates in the 6-7%/year range
Projected Capacity Additions (GW)		
-- Total Additions	10-12.5	Range reflects some uncertainty over demand growth, coal subsidies and gas availability
-- Gas-Fired CT/CC Additions	6.5-8.5	4.8 GW approved in 2000, another 3.2 GW approved in 2001; potential for 4-7 GW of merchant independent power additions
Implied Capacity Displacement (GW)	1-1.5	Potentially from new, gas-fired merchant, independent power plants

APPENDIX F: INTERNATIONAL COMPETITIVE PHASE OUTLOOK

Appendix F -- International Competitive Phase Outlook (2007-2020)

BRAZIL		
Projected Demand Growth (%/yr)	3-5%	Long-term forecasts range from 3%/yr to 5%/yr
Projected Capacity Additions (GW)		
-- Total Additions	55-75	Uncertainties include demand growth, the ability to develop large hydroelectric plants (including more than 30 GW in the Amazon basin) and potential additional nuclear additions (e.g., 2.5 GW planned for 2005-2015)
-- Gas-Fired CT/CC Additions	15-30	Based on estimate of gas-fired additions accounting for about 30-40% of total additions, compared with 40% or more over the 2000-2006 period
Implied Capacity Displacement (GW)	0	Little economic displacement forecasted until 2012-14.

MEXICO		
Projected Demand Growth (%/yr)	3.5-5%	Long-term forecasts range from about 3.5%/yr to 5%/yr
Projected Capacity Additions (GW)		
-- Total Additions	28-39	Based on projected range of long-term demand growth and minimum 10-15% reserve margin
-- Gas-Fired CT/CC Additions	23-30	Based on estimate of 70-80% of future total additions
Implied Capacity Displacement (GW)	0-3.5	Little economic displacement forecasted until 2010-12 but some old CFE units will be candidates.

Appendix F -- International Competitive Phase Outlook (2007-2020)

GERMANY		
Projected Demand Growth (%/yr)	1-1.5%	Modest growth expected long-term; high-end projections only about 2%
Projected Capacity Additions (GW)		
-- Total Additions	20-35	Long-term outlook will be influenced by decisions on nuclear capacity (22 GW); current plans call for all capacity to be retired at end of 32 year licenses (by 2021), industry wanted extensions to 35 years
-- Gas-Fired CT/CC Additions	10-22	Long-term outlook influenced by future gas and prices (both expected to be favorable) and by regulations/taxes affecting coal-fired plants
Implied Capacity Displacement (GW)	6-12	More and more merchant additions aimed at displacing or competing with capacity that could be retired post 2008-2009

ITALY		
Projected Demand Growth (%/yr)	2-3%	Long-term growth expected to moderate even further from baseline period growth
Projected Capacity Additions (GW)		
-- Total Additions	22-31	Assumes availability of current capacity (now under 80%) is improved to 85-90% range and new capacity is need to cover both growth and 10-15 GW of net capacity losses from retirements/conversions; Italy has an objective of 7 GW of renewable energy by 2012, but is not likely to be met based on current efforts
-- Gas-Fired CT/CC Additions	12-22	Excludes oil-to-gas conversions; gas favored fuel to meet environmental objectives
Implied Capacity Displacement (GW)	5-9	Increasing displacement potential from new merchant plants post 2010-2012

SPAIN		
Projected Demand Growth (%/yr)	3-4%	Somewhat slower long-term growth likely
Projected Capacity Additions (GW)		
-- Total Additions	24-37	Capacity requirements a function of demand growth and potential nuclear retirements, likely to be at least 4-6 GW out of the existing 7.4 GW of current nuclear capacity. Plus some coal plant retirements to be expected.
-- Gas-Fired CT/CC Additions	16-27	Gas capacity likely to be favored, although coal is predominant local resource; gas additions could be higher if additional taxes penalize coal or if coal production decreases from reduce subsidies; Spanish government also has amibitions for large additions of wind and waste-to-energy capacity which could reduce gas additions
Implied Capacity Displacement (GW)	3-10	Displacement of coal-fired plants

Appendix F - Market Prospects in Brazil (2007-2020)

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	9.2	19.75	14%	36%	50%	*30*	*360*	*185*
Industrial Cogeneration	4	6	50%	50%	0%	*30*	*300*	*142*
Combined Heat and Power	0.4	0.75	61%	39%	0%	*30*	*100*	*66*
Repowering	0.7	2	67%	33%	0%	*100*	*300*	*215*
IGCC	0	0				--	--	--
Distributed Generation	0.7	1.5	0%	45%	55%	*30*	*100*	*70*
TOTAL	**15**	**30**	**26%**	**40%**	**35%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150- 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	12	4.7	9.2	39%	77%	27%	53%
Industrial Cogeneration	3	2.2	3.0	67%	92%	13%	17%
Combined Heat and Power	0	0.4	0.4	99%	99%	2%	2%
Repowering	1	0.0	0.6	0%	71%	0%	4%
IGCC	0	0.0	0.0	0%	0%	0%	0%
Distributed Generation	1	0.9	0.9	100%	100%	5%	5%
TOTAL	**17**	**8.2**	**14.1**	**47%**	**81%**	**47%**	**81%**

SOURCE: PA Consulting

Appendix F - Market Prospects in Mexico (2007-2020)

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	17.0	20.3	26%	27%	48%	*30*	*360*	*190*
Industrial Cogeneration	3.5	5.0	82%	18%	0%	*30*	*300*	*143*
Combined Heat and Power	0.3	0.5	67%	33%	0%	*30*	*100*	*61*
Repowering	1.5	2.8	94%	6%	0%	*150*	*300*	*219*
IGCC	0.5	1.3	100%	0%	0%	*150*	*300*	*225*
Distributed Generation	0.8	1.5	56%	44%	0%	*30*	*150*	*63*
TOTAL	**23.5**	**31.3**	**44%**	**24%**	**32%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150- 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	15	5.5	10.4	36%	68%	26%	50%
Industrial Cogeneration	3	1.9	2.5	69%	90%	9%	12%
Combined Heat and Power	0	0.2	0.2	98%	98%	1%	1%
Repowering	1	0.0	0.9	0%	62%	0%	4%
IGCC	1	0.0	0.3	0%	0%	0%	1%
Distributed Generation	1	0.7	0.7	100%	100%	3%	3%
TOTAL	**21**	**8.4**	**15.0**	**40%**	**72%**	**40%**	**72%**

SOURCE: PA Consulting

Appendix F - Market Prospects in Germany (2007-2020)

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	4.5	9.5	0%	39%	61%	*30*	*360*	*225*
Industrial Cogeneration	1.5	3.5	36%	52%	12%	*30*	*300*	*168*
Combined Heat and Power	1	2.5	23%	57%	20%	*30*	*200*	*118*
Repowering	2	4	47%	53%	0%	*100*	*360*	*240*
IGCC	2	4	83%	17%	0%	*150*	*360*	*265*
Distributed Generation	1	2.5	17%	34%	49%	*30*	*150*	*89*
TOTAL	**12**	**26**	**29%**	**41%**	**31%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150- 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	6	1.1	3.0	19%	49%	8%	21%
Industrial Cogeneration	2	0.9	1.1	50%	61%	6%	7%
Combined Heat and Power	1	1.1	1.3	84%	100%	7%	9%
Repowering	2	0.4	0.8	21%	41%	3%	5%
IGCC	2	0.0	0.4	0%	0%	0%	3%
Distributed Generation	1	1.4	1.4	100%	100%	10%	10%
TOTAL	**14**	**4.9**	**7.9**	**34%**	**55%**	**34%**	**55%**

SOURCE: PA Consulting

Appendix F - Market Prospects in Italy (2007-2020)

	Market Size (MW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	6	8.75	7%	27%	66%	*50*	*360*	*212*
Industrial Cogeneration	1.5	3	44%	38%	18%	*30*	*300*	*177*
Combined Heat and Power	1	1.75	20%	36%	44%	*30*	*200*	*119*
Repowering	2	5	86%	14%	0%	*100*	*300*	*229*
IGCC	1.5	2.5	100%	0%	0%	*150*	*360*	*267*
Distributed Generation	1.5	3.5	16%	44%	40%	*30*	*150*	*80*
TOTAL	**13.5**	**24.5**	**38%**	**26%**	**36%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150- 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	6	2.0	3.5	31%	54%	14%	24%
Industrial Cogeneration	2	0.7	1.1	45%	67%	5%	7%
Combined Heat and Power	1	0.9	1.1	82%	100%	6%	7%
Repowering	2	0.1	1.0	6%	43%	1%	7%
IGCC	1	0.0	0.4	0%	0%	0%	3%
Distributed Generation	2	2.0	2.0	100%	100%	13%	13%
TOTAL	**15**	**5.7**	**9.1**	**39%**	**61%**	**39%**	**61%**

SOURCE: PA Consutling

Appendix F - Market Prospects in Spain (2007-2020)

	Market Size (GW)		Per Duty Cycle (%)			Gas Turbine Size Range (MW)		
CC/SC Application	Low	High	Base	Intermediate	Peaking	Low	High	Average
Pure Power Generation	11.5	17.8	20%	34%	45%	*30*	*360*	*215*
Industrial Cogeneration	1.5	3.2	47%	43%	11%	*30*	*360*	*215*
Combined Heat and Power	0.5	1	0%	100%	0%	*30*	*150*	*95*
Repowering	1.5	3	100%	0%	0%	*100*	*300*	*228*
IGCC	1	2	100%	0%	0%	*150*	*300*	*231*
Distributed Generation	1	2	0%	67%	33%	*30*	*150*	*77*
TOTAL	**17**	**29**	**34%**	**34%**	**32%**			

Mid-Case Estimate	Total GT	GT Capacity (GW) below 150-200 MW		GT Capacity Share (%) By CC/SC Segment		Share (%) of Overall GT Capacity <150- 200 MW	
CC/SC Application	Capacity/GW	<150 MW	<200 MW	<150 MW	<200 MW	<150 MW	<200 MW
Pure Power Generation	12	3.2	6.6	27%	55%	18%	37%
Industrial Cogeneration	2	0.7	1.0	43%	63%	4%	6%
Combined Heat and Power	0	0.5	0.5	101%	101%	3%	3%
Repowering	1	0.1	0.6	9%	40%	1%	3%
IGCC	1	0.0	0.5	0%	0%	0%	3%
Distributed Generation	1	1.2	1.2	100%	100%	7%	7%
TOTAL	**18**	**5.6**	**10.3**	**32%**	**58%**	**32%**	**58%**

SOURCE: PA Consulting

APPENDIX G:MAJOR REFERENCE SOURCES

Annual Energy Outlook 2000, U.S. Department of Energy, Energy Information Administration, December 1999.

Annual Energy Outlook 2001, U.S. Department of Energy, Energy Information Administration, December 2000.

Annual Energy Outlook 2002, U.S. Department of Energy, Energy Information Administration, December 2001.

Baseline Projection Data Book, 2000 Edition, Gas Research Institute, 1999.

Brazil, Country Analysis Brief, U.S. Department of Energy, Energy Information Administration, June 2000.

CFE Annual Report 2000

Electricity in Italy, Financial Times Energy, 1999.

Electricity Information 2000, International Energy Agency, 2000.

ES&D 2000, Electricity Supply & Demand Database, North American Electric Reliability Council, July 2000.

ES&D 2001 Electricity Supply & Demand Database, North American Electric Reliability Council, July 2001.

Explanatory Note on The *Valor Normativo* (Reference Prices), Brazilian Electricity Regulatory Agency (ANEEL), October 26, 1999.

Germany, Country Analysis Brief, U.S. Department of Energy, Energy Information Administration, November 2000.

International Energy Outlook 2000, U.S. Department of Energy, Energy Information Administration, 2000.

International Private Power Quarterly, McGraw-Hill Companies, 2000.

"Investment Opportunities in the Electric Sector," Government of Mexico (from www.energia.gob.mx website), 2000.

Italy, Country Analysis Brief, U.S. Department of Energy, Energy Information Administration, December 1999.

Mexico, Country Analysis Brief, U.S. Department of Energy, Energy Information Administration, February 2000.

Natural Gas Outlook 2000, WEFA, Inc. 2000.

North America and International Independent Power Databases, PA Consulting Group, 2000.

Plano Decenal, 1999-2009, Eletrobras, Brazil, 1999.

Policy Proposal for Structural Reform of the Mexican Electricity Industry, Secretaria de Energia, Mexico, 1999.

"Power Markets in Europe: An Overview," FT Energy, November 2000.

"Privatizing the Electric Power Sector in Brazil," Carlos Kawall Leal Ferreira, Professor of Economics, Catholic University of Sao Paulo, 1998.

Sector Electrico, Prospectiva 2000-2009, Secretaria de Energia, Mexico, 1999.

Spain, Country Analysis Brief, U.S. Department of Energy, Energy Information Administration, December 1999.

Ten-Year Expansion Plan, 1998-2007, Eletrobras, Brazil, 1998.

"The Price Outlook for Wholesale Power in ERCOT," Dr. K. Farney, WEFA, Inc., presented to the Gulf Coast Power Association, May 2000.

Corporate headquarters

123 Buckingham Palace Road
London SW1W 9SR
United Kingdom
Tel: +44 20 7730 9000
Fax: +44 20 7333 5050
E-mail: info@paconsulting.com

PA Consulting Group

www.paconsulting.com

PA Consulting Group is a leading management, systems and technology consulting firm, operating worldwide from over 40 offices in more than 20 countries.

Offices in North and South America

Arlington
1530 Wilson Boulevard
Suite 400
Arlington, VA 22209
Tel: +1 703 351 0300
Fax: +1 703 351 0342

Boulder
1881 Ninth Street
Suite 302
Boulder, CO 80302
Tel: +1 303 449 5515
Fax: +1 303 443 5684

Cambridge, MA
One Memorial Drive
Cambridge, MA 02142
Tel: +1 617 225 2700
Fax: +1 617 225 2631

41 William Linskey Way
Cambridge, MA 02142
Tel: +1 617 864 8880
Fax: +1 617 864 8884

Houston
Three Riverway
Suite 300
Houston, TX 77056
Tel: +1 713 403 5250
Fax: +1 713 961 4153

Los Angeles
520 South Grand Avenue
Suite 500
Los Angeles, CA 90071
Tel: +1 213 689 1515
Fax: +1 213 689 1129

Madison
2711 Allen Boulevard
Suite 200
Middleton, WI 53562
Tel: +1 608 827 7820
Fax: +1 608 827 7815

New York
The Chrysler Building
405 Lexington Avenue
New York, NY 10174
Tel: +1 212 973 5900
Fax: +1 212 973 5959

630 Fifth Avenue
Suite 1465
45 Rockefeller Plaza
New York, NY 10111
Tel: +1 212 218 3000
Fax: +1 212 218 3010

Palo Alto
100 Hamilton Avenue
Suite 200
Palo Alto, CA 94301
Tel: +1 650 322 1300
Fax: +1 650 322 1479

Princeton
315A Enterprise Drive
Plainsboro, NJ 08536
Tel: +1 609 936 8300
Fax: +1 609 936 8811

Washington, DC
1776 Eye Street, NW
Washington, DC 20006
Tel: +1 202 223 6665
Fax: +1 202 296 3858

Argentina
Cerrito No 866
Piso 6 & 9 (1336)
Buenos Aires
Tel: +54 11 4813 9898
Fax: +54 11 4811 9855

Canada
4 King Street West
Suite 1310
Toronto Ontario M5H 1B6
Tel: +1 416 360 6500
Fax: +1 416 360 7201

Principal national offices in

Argentina, Australia, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Indonesia, Ireland, Japan, Malaysia, Netherlands, New Zealand, Norway, People's Republic of China *(offices in Beijing and Hong Kong)*, Russian Federation, Singapore, Sweden, United Kingdom, United States